UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

07048697

P.E.
3/1/07

FORM 6-K

Report of Foreign Private Issuer Pursuant to Rule 13a-16 or 15d-16
Under the Securities Exchange Act of 1934

For the month of March 2007

Commission File Number: 001-04307

Husky Energy Inc.
(Translation of registrant's name into English)

707 8th Avenue S.W., Calgary, Alberta, Canada T2P 1H5
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F _____ Form 40-F _X_

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1). _X_

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): _____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes _______ No _X_

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-_______.

On March 23, 2007, Husky Energy Inc. filed, and mailed to its shareholders, its annual report for the fiscal year ended December 31, 2006. The annual report is attached hereto as Exhibit A.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HUSKY ENERGY INC.

By: ______________________

James D. Girgulis
Vice President, Legal &
Corporate Secretary

Date: March 23, 2007

Husky Energy Inc.
Annual Report

2006

Clear vision Financial discipline Project execution

"Husky's value creation strategy has three components – a clear vision of what we want to achieve, rigorous financial discipline, and safe and timely project execution. This strategy is the blueprint for our continued success."

John C. S. Lau

President & Chief Executive Officer

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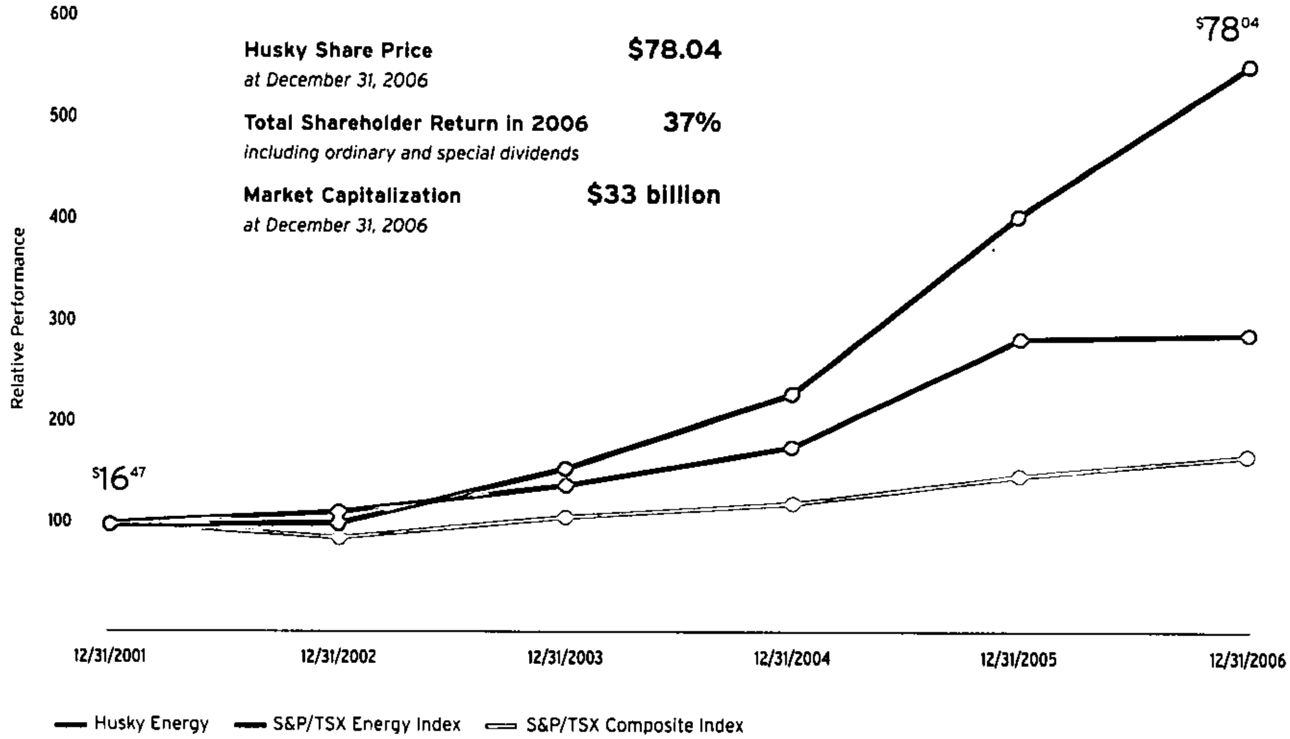
Husky Share Price vs Indices



Corporate

MISSION **To maximize returns to our shareholders in a socially responsible manner.**

VISION **To create superior shareholder value through financial discipline and a quality asset base.**

PROFILE Husky Energy Inc. is a Canadian integrated energy and energy-related company with operations in upstream, midstream and refined products.

Upstream includes the exploration, development and production of crude oil, bitumen and natural gas in Western Canada, offshore the Canadian East Coast, in the South and East China Seas, offshore Indonesia and other international areas.

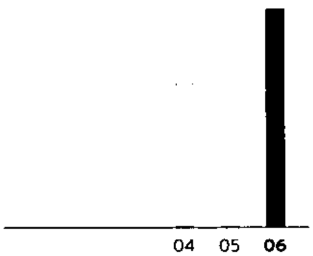
Midstream operations include the upgrading of heavy crude oil into premium synthetic crude oil, pipeline transportation, gas storage, cogeneration, and the marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined products operations include the refining, marketing and distribution of gasoline, diesel, asphalt, ethanol, and ancillary services in Canada, the United States, and a network of retail outlets from Ontario to British Columbia and the Yukon.

Husky Energy Inc. is headquartered in Calgary, Alberta, Canada, and is listed on the Toronto Stock Exchange under the symbol HSE.

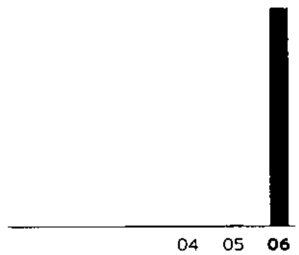
Revenue
($ millions)

12,664



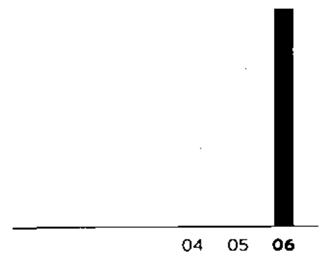
Cash Flow from Operations
($ millions)

4,501



Net Earnings
($ millions)

2,726



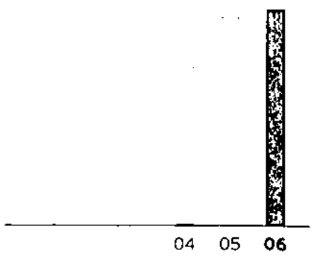
2006 HIGHLIGHTS

Year ended December 31	2006	2005
(millions of dollars except where indicated)		
Financial		
Sales and operating revenues,		
net of royalties	**12,664**	10,245
Cash flow from operations	**4,501**	3,785
Per share *(dollars)* – Basic	**10.61**	8.93
– Diluted	**10.61**	8.93
Net earnings	**2,726**	2,003
Per share *(dollars)* – Basic	**6.43**	4.72
– Diluted	**6.43**	4.72
Dividends		
Per share *(dollars)* – Ordinary	**1.50**	0.65
– Special	**-**	1.00
Capital expenditures [(1)]	**3,201**	3,099
Return on average		
capital employed *(percent)*	**27.0**	22.8
Return on equity *(percent)*	**31.8**	29.2
Debt to capital employed *(percent)*	**14.3**	20.1
Debt to cash flow from		
operations *(times)*	**0.4**	0.5

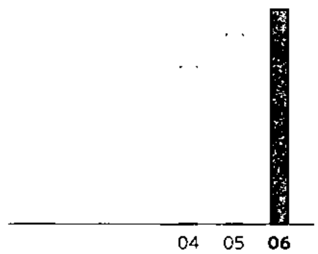
(1) Excludes capitalized costs related to asset retirement obligations incurred during the period.

Year ended December 31	2006	2005
Operating		
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**111.0**	64.6
Medium crude oil *(mbbls/day)*	**28.5**	31.1
Heavy crude oil *(mbbls/day)*	**108.1**	106.0
Total crude oil & NGL *(mbbls/day)*	**247.6**	201.7
Natural gas *(mmcf/day)*	**672.3**	680.0
Total *(mboe/day)*	**359.7**	315.0
Proved reserves, before royalties		
Light crude oil & NGL *(mmbbls)*	**287**	273
Medium crude oil *(mmbbls)*	**87**	91
Heavy crude oil *(mmbbls)*	**213**	217
Bitumen *(mmbbls)*	**60**	48
Natural gas *(bcf)*	**2,143**	2,136
Total *(mmboe)*	**1,004**	985
Upgrader throughput *(mbbls/day)*	**71.0**	66.6
Synthetic crude oil sales *(mbbls/day)*	**62.5**	57.5
Pipeline throughput *(mbbls/day)*	**475**	474
Light oil sales *(million litres/day)*	**8.7**	8.9
Asphalt product sales *(mbbls/day)*	**23.4**	22.5
Refinery throughput *(mbbls/day)*	**36.1**	35.2
Ethanol production *(thousand litres/day)*	**59.7**	25.6

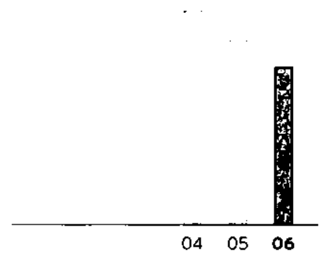
Capital Expenditures
($ millions)
3,201



Total Assets
($ millions)
17,933



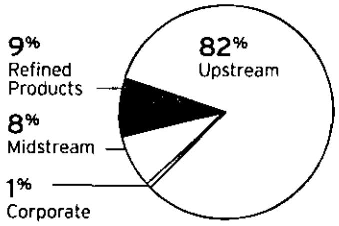
Total Debt
($ millions)
1,611



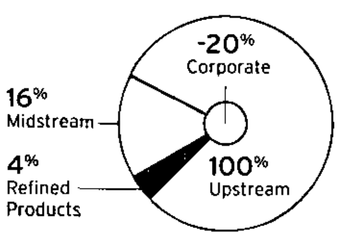
2006 HIGHLIGHTS

It was a record year for production, net earnings and cash flow. Husky's key operational successes included completion of the Tucker Oil Sands Project on schedule and under budget, record performance at the White Rose oil field, a large natural gas discovery offshore China, and commissioning of the Lloydminster Ethanol Plant.

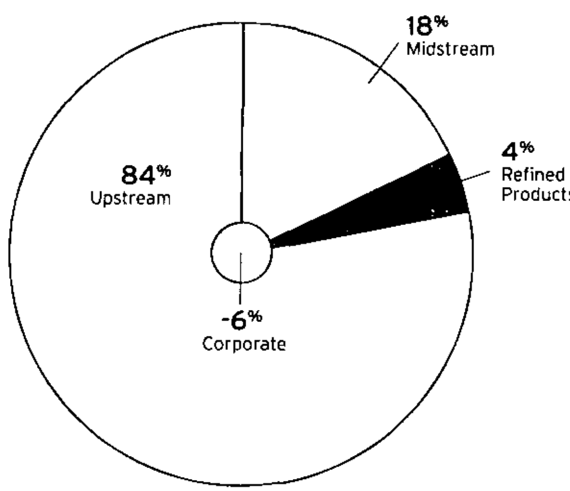
Capital Expenditures



Cash Flow from Operations

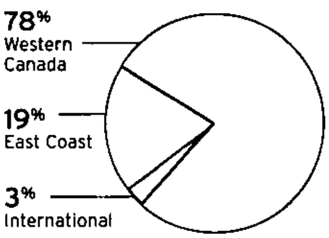


Net Earnings

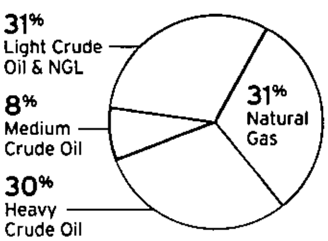


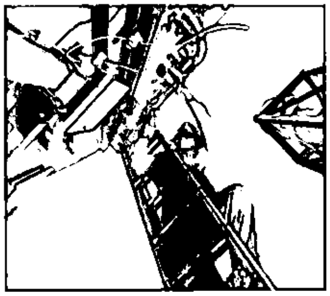
At a Glance

2006 Oil and Gas Production
359,700 boe/day



2006 Product Mix





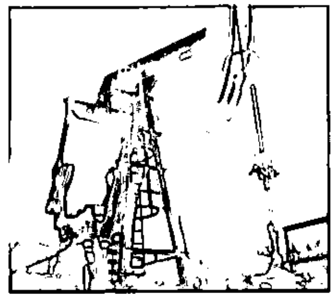
1. Western Canada

Business
- Crude oil and natural gas exploration and production

Strategy
- Focus on natural gas exploration in the Foothills and Deep Basin, and tight gas and coal bed methane (CBM) in the Plains regions
- Increase recovery from mature fields through enhanced recovery techniques

2006 Achievements
- Increased CBM production to 32 mmcf/day
- Completed the Warner alkaline surfactant polymer (ASP) flood project

2007 Plans
- Achieve oil and gas reserve replacement over 100%
- Complete construction and commission the Crowsnest ASP project
- Drill 50 exploration wells in Western Canada
- Complete 3-D seismic program at Summit Creek, NT



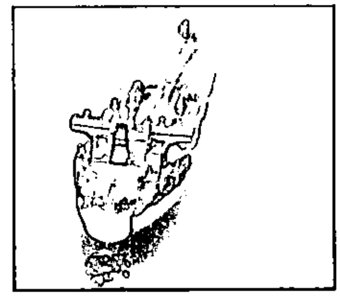
2. Heavy Oil

Business
- Heavy oil production in the Lloydminster area of Alberta and Saskatchewan

Strategy
- Optimize and expand heavy oil production, the upstream component of Husky's integrated business operations in Lloydminster

2006 Achievements
- Achieved annual average oil production of 108,100 bbls/day
- Identified future thermal projects
- Conducted a successful cold enhanced recovery field pilot

2007 Plans
- Maintain production volumes through exploitation of primary and thermal properties
- Progress engineering on thermal projects
- Conduct further cold enhanced recovery pilot work



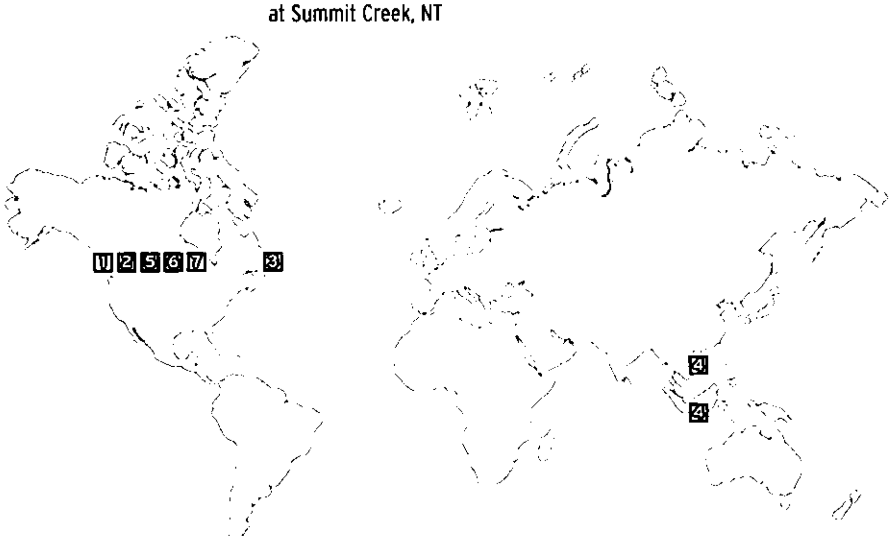
3. Canada's East Coast

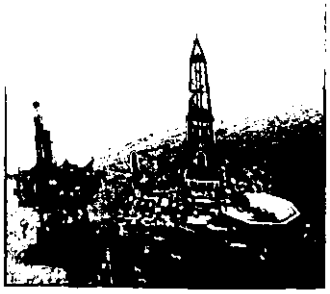
Business
- 72.5% interest in, and operator of the White Rose oil field
- 12.51% interest in the Terra Nova oil field
- 1.2 million acres of exploration acreage and holder of 16 Significant Discovery Licences

Strategy
- Maximize value of the White Rose assets through short- and long-term oil and gas production growth
- Develop satellite oil pools to extend field life of White Rose
- Participate in continuing development at Terra Nova
- Evaluate development alternatives for natural gas
- Identify prospects for exploration and delineation

2006 Achievements
- Increased White Rose reservoir production capacity to 125,000 bbls/day
- Completed a successful delineation program at the White Rose field
- Started production from the Terra Nova Far East Flank
- Acquired three exploration blocks in the Jeanne d'Arc Basin

2007 Plans
- Bring seventh production well on-stream at White Rose
- Increase daily production capacity of the *SeaRose FPSO*
- Delineate the White Rose West Avalon pool
- Complete drilling and evaluate results from the Far East South delineation well at Terra Nova
- Drill Wild Rose exploration prospect





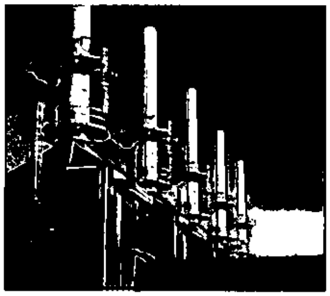
4. International

Business
- 40% interest in the Wenchang oil field in the South China Sea
- Seven exploration blocks in the South and East China Seas
- 100% working interest in two exploration blocks offshore Indonesia

Strategy
- Create a material oil and gas business in Southeast Asia

2006 Achievements
- Three infill wells drilled and an LPG production facility brought on-stream at Wenchang
- Made one of the largest natural gas discoveries offshore China at Liwan 3-1-1
- Awarded three blocks in the South China Sea
- Awarded the East Bawean II Block in the East Java Sea

2007 Plans
- Complete 3-D seismic on Blocks 29/26 and 29/06 in the South China Sea
- Evaluate commercial options for the Liwan discovery
- Drill exploration well on Block 04/35 in the East China Sea
- Commence development of the Madura BD field
- Commence a 3-D seismic program over the East Bawean II Block



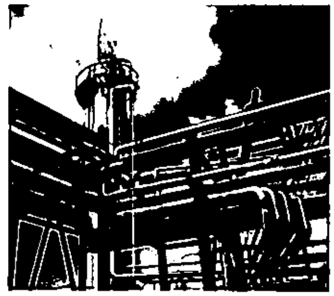
5. Oil Sands

Business
- Landholdings of 510,890 acres with a discovered resource of 40.86 billion barrels

Strategy
- Develop in-situ bitumen resources integrated with downstream processing

2006 Achievements
- Tucker Oil Sands Project completed on schedule and under budget
- Completed conceptual design for the Sunrise Oil Sands Project
- Applied for regulatory approval for 10,000 bbls/day demonstration project at Caribou Lake
- Acquired 84,320 additional acres with a discovered resource of 7.3 billion barrels at Saleski

2007 Plans
- Ramp up production at the Tucker Oil Sands Project
- Complete FEED and identify downstream solution for the Sunrise Oil Sands Project
- Obtain regulatory approval and progress engineering for the Caribou Lake Oil Sands Project
- Identify potential recovery processes for the Saleski Oil Sands Project



6. Midstream

Business
- Upgrading of heavy oil into premium synthetic crude oil
- 2,087-kilometre crude oil pipeline system
- Crude oil and natural gas storage
- Electricity cogeneration
- Marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke

Strategy
- Increase upgrader capacity to meet future heavy oil and bitumen production volumes
- Increase and optimize crude oil pipeline capacity
- Increase value of Husky's assets through growth in the commodity marketing business

2006 Achievements
- Increased crude oil storage at the Hardisty terminal by 23%
- Initiated mainline pipeline capacity expansion
- Increased gas storage business by 38% to 33.5 bcf
- Commodity Marketing volumes exceeded 1 mmboe/day
- Designed and implemented marketing program for White Rose

2007 Plans
- Complete upgrader debottlenecking project
- Complete conceptual engineering to double upgrader capacity
- Complete mainline pipeline expansion project from Lloydminster to the Hardisty terminal
- Increase Commodity Marketing volumes to 1.1 mmboe/day
- Design marketing plan for the Liwan discovery

7. Refined Products

Business
- Retail network of over 500 units
- 12,000 bbls/day refinery at Prince George, BC
- 28,000 bbls/day asphalt refinery at Lloydminster, AB
- 10 million litres per year ethanol plant in Minnedosa, MB
- 130 million litres per year ethanol plant in Lloydminster, SK

Strategy
- Enhance outlets with technology, facility upgrades and ancillary sales
- Optimize product supply agreements
- Increase asphalt sales
- Become Western Canada's largest producer of ethanol

2006 Achievements
- Achieved record fuel volume per location
- Achieved record throughput at the Lloydminster Asphalt Plant
- Completed and commissioned the Lloydminster Ethanol Plant
- Completed the Prince George Refinery Clean Fuels Project and increased throughput to 12,000 bbls/day

2007 Plans
- Increase fuel volume throughput per location over 2006
- Increase ancillary income over 2006
- Complete and commission the Minnedosa Ethanol Plant
- Expand asphalt sales distribution in the U.S.

2006 Production	Net Earnings	Cash Flow from Operations
359,700 boe/day	$2,726 million	$4,501 million

Husky's Value Creation

The following illustrates how Husky has created value over the years.

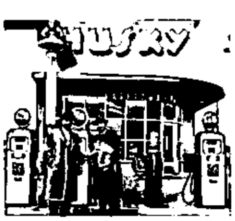
1938 *to* 1980

1938
The Husky Refining Company was incorporated in Cody, Wyoming, United States.

1946
The Husky refinery was moved to Lloydminster, Alberta, Canada.

Husky Oil and Refining Ltd. was incorporated with its headquarters in Calgary, Alberta.

1976
Husky acquired the Prince George Refinery, and the marketing and refining assets of Union Oil Company.



1981 *to* 1999

1987
Husky went into private ownership.

1988
Husky acquired Canterra Energy.

1992
The Company and the governments of Canada, Alberta and Saskatchewan completed construction of the Bi-Provincial Upgrader at Lloydminster.

1998
Husky acquired 100 percent of the Bi-Provincial Upgrader.

The Company acquired Mohawk Canada.

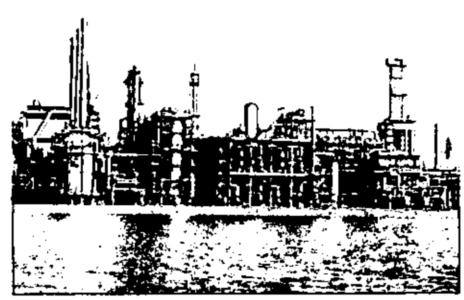
2000

2000
Husky acquired Renaissance Energy and was listed on the Toronto Stock Exchange.

The Company and its partner commenced development of the Wenchang oil field in the South China Sea.

2001

2001
Husky received regulatory approval for the White Rose oil field, offshore Newfoundland and Labrador.



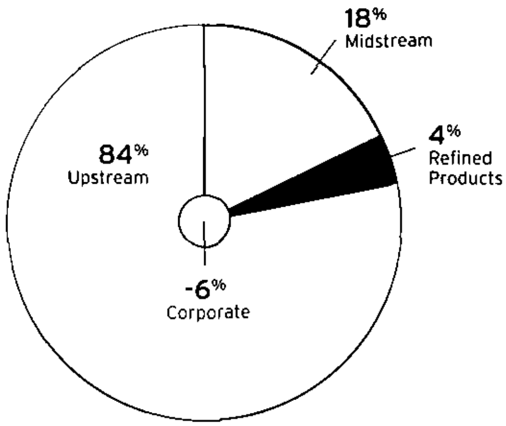
2002

2002
Husky sanctioned the development of White Rose.

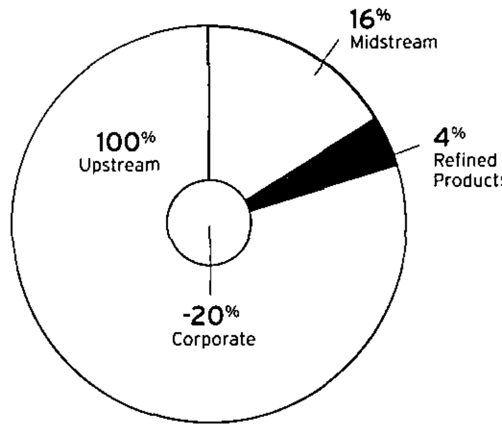
Production commenced at the Terra Nova oil field, offshore Newfoundland and Labrador.

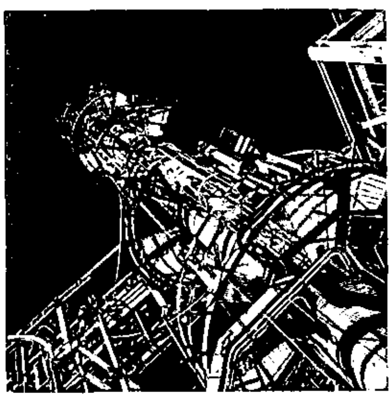
Husky achieved first oil at the Wenchang oil field.

Net Earnings



Cash Flow from Operations





2005
First oil was produced at White Rose ahead of schedule and on budget.

Husky made a hydrocarbon discovery in the Central Mackenzie Valley of the Northwest Territories.

Construction commenced on the 130 million litres per year Minnedosa Ethanol Plant.

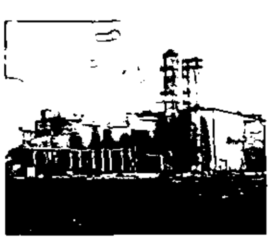
2003
Husky acquired Marathon Canada.

2003 2004 2005 2006

2004
Husky received regulatory approval and sanctioned the construction of the Tucker Oil Sands Project.

The Company acquired the outstanding interests of the Madura BD and MDA fields, offshore Indonesia.

Construction commenced on the 130 million litres per year Lloydminster Ethanol Plant.



2006
The Tucker Oil Sands Project was completed on-schedule and under budget.

Production capacity at White Rose reached 125,000 barrels per day.

Two significant hydrocarbon discoveries were made in the Southwest and West White Rose pools.

Husky made a significant gas discovery at Liwan in the South China Sea.

Husky signed three petroleum contracts for further exploration in the South China Sea.

The Lloydminster Ethanol Plant was completed.

Husky completed the Clean Fuels Project at the Prince George Refinery which increased throughput capacity by 20 percent.

Report to Shareholders

It is our great pleasure to report that 2006 was another record year for Husky Energy. The Company's total sales and operating revenues, net of royalties, increased 24 percent to $12.7 billion. Net earnings and cash flow from operations reached $2.7 billion and $4.5 billion respectively. Return on equity exceeded 31 percent. The close of 2006 marked a three-year period of unprecedented compound growth of 36 percent.

The Company achieved record production in 2006. Husky's total production volume averaged 360,000 barrels of oil equivalent per day, compared to 315,000 barrels of oil equivalent per day in 2005, an increase of 14 percent.

Husky's financial performance was supported by the continuing strength of oil and gas prices. The 2006 capital expenditures increased to $3.2 billion from $3.1 billion in 2005. The increase was due mainly to the startup of the Tucker Oil Sands Project, development work for the proposed Sunrise Oil Sands Project, and the rising costs from operating in the Western Canadian Sedimentary Basin.

Net earnings exceeded $2.7 billion, an increase of 36%

HIGHLIGHTS

During 2006, Husky achieved a number of successes.

The Tucker Oil Sands Project, northwest of Cold Lake, Alberta was completed on-schedule and under its $500 million budget. Production of more than 30,000 barrels per day of bitumen is expected during its 35-year lifecycle.

The Sunrise Oil Sands Project front-end engineering design work is expected to be completed by the third quarter of 2007. To maximize the value of this substantial resource, alternatives are being evaluated for the upgrading, transporting and refining of bitumen produced from the project.

The Company also acquired leases adjacent to its Saleski oil sands property, increasing its holdings to 239,200 acres with discovered resources estimated at 24.1 billion barrels of bitumen.

The White Rose oil field, in which Husky holds a 72.5 percent working interest and is

the operator, continued to perform better than expected. By year-end, production capacity at the field reached 125,000 barrels of oil per day. The 2006 White Rose delineation program yielded two significant discoveries and contributed possible reserves of 138 million barrels of oil.

Average daily production reached a record 360,000 barrels of oil equivalent

The Company announced a significant natural gas discovery in the South China Sea at Liwan 3-1-1 on Block 29/26. This discovery has a contingent resource of four to six trillion cubic feet of natural gas. Seismic work will be conducted in 2007 to identify potential targets for further exploration and delineation. A deep water rig has been secured for delivery in 2008.

For Husky's midstream and refined products operations, the Company proceeded with the expansion of its mainline crude oil pipeline between Lloydminster and its terminal at Hardisty, Alberta. This will accommodate increased production from the Tucker Oil Sands Project and shipments from third parties.

The Lloydminster Ethanol Plant was commissioned in August 2006 and is the largest wheat-based ethanol plant in Western Canada. When full production is achieved, it will produce annually 130 million litres of ethanol and 134,000 tonnes of a high protein animal feed supplement. A second 130 million litres per year ethanol plant is being constructed in Minnedosa, Manitoba and is scheduled to be operational by the third quarter of 2007.

In response to the Government of Canada's regulations for low-sulphur gasoline and diesel fuels, the Company completed a Clean Fuels Project at the Prince George Refinery. The Company also completed the debottleneck of the refinery and increased its throughput capacity by 20 percent to 12,000 barrels per day.

Cash flow from operations grew 19% to $4.5 billion

We are pleased to report that Standard and Poor's Rating Services raised Husky's long-term credit and senior unsecured debt ratings to BBB+ with a stable outlook. The new rating reflects the strength of Husky's balance sheet as demonstrated by our low debt ratios. Debt to capital employed was 14 percent and debt to cash flow from operations was 0.4 times at December 31, 2006.

Report to Shareholders

Husky is well-positioned for continued growth and expansion. The Company's proven and probable reserves were 2.4 billion barrels of oil equivalent at the end of 2006. This resource base provides a solid foundation for the Company's continued production growth.

Husky is committed to its value creation strategy

OUTLOOK

With a robust project portfolio, a proven strategy for creating value and reasonable commodity prices, we expect continued strong growth for Husky. For 2007, the Company has a capital program of $3.18 billion for the ongoing exploration and development of its asset base in Western Canada, offshore Canada's East Coast and internationally. Husky's 2007 production is forecast to be between 390,000 to 410,000 barrels of oil equivalent per day, an increase of 8 to 14 percent from 2006.

As one of Husky's objectives is to be a leader in value creation, we are committed to maintaining our decade-long record of growth. Through our focus on clear vision, financial discipline and project execution, Husky has developed a diverse portfolio of assets that we fully expect will bring financial results and continued growth opportunities well into the future.

Husky's consistent performance in creating value for our shareholders is made possible through the commitment, dedication and hard work of our management team and employees, and the continued loyalty of our shareholders. On behalf of the Board of Directors, we offer our most sincere appreciation and thanks.

Victor T. K. Li
Co-Chairman

Canning K. N. Fok
Co-Chairman

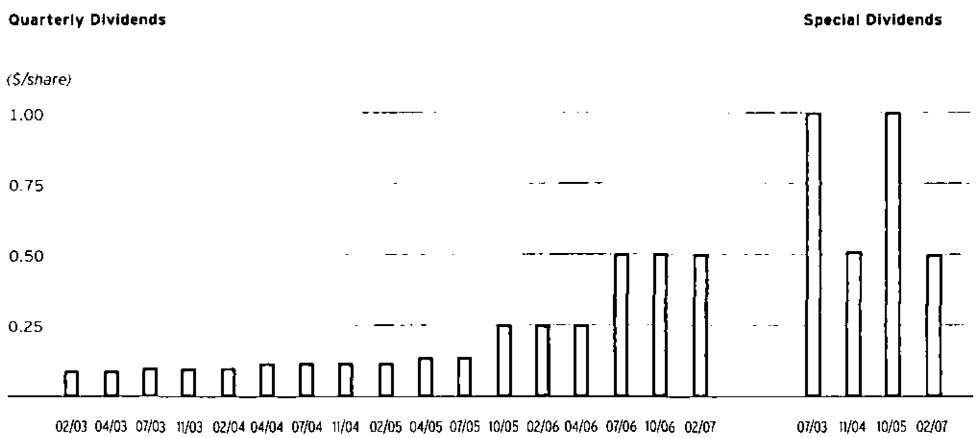
John C. S. Lau
President & Chief Executive Officer

February 5, 2007

Dividends

On February 5, 2007, the Board of Directors approved a final quarterly dividend for the year 2006 of $0.50 per share, and a special dividend of $0.50 per share, allowing shareholders to benefit directly from Husky's strong balance sheet, and record earnings and cash flow.

The Board of Directors will continue to review the Company's dividend policy from time to time based on its sustainable earnings, financial position and growth prospects.

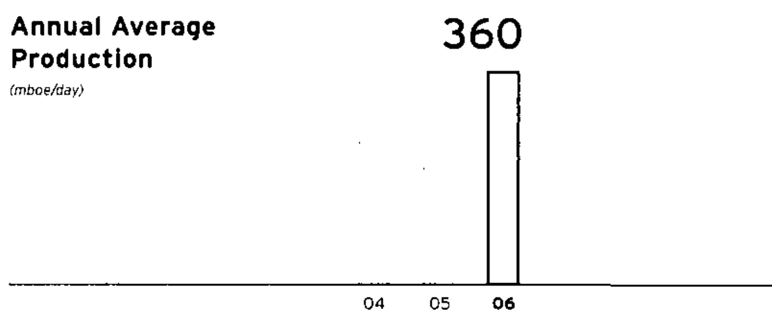


The Canadian Revenue Agency has advised that pubic corporations should provide notification on their websites and in their corporate quarterly or annual reports or publications that pursuant to a new tax law, Canadian residents who receive "eligible dividends" in 2006 and subsequent years will be entitled to an enhanced gross-up and dividend tax credit on such dividends. Unless indicated, all dividends paid on Husky Energy Inc. common shares in 2006 and subsequent years qualify as "eligible dividends" for these purposes.

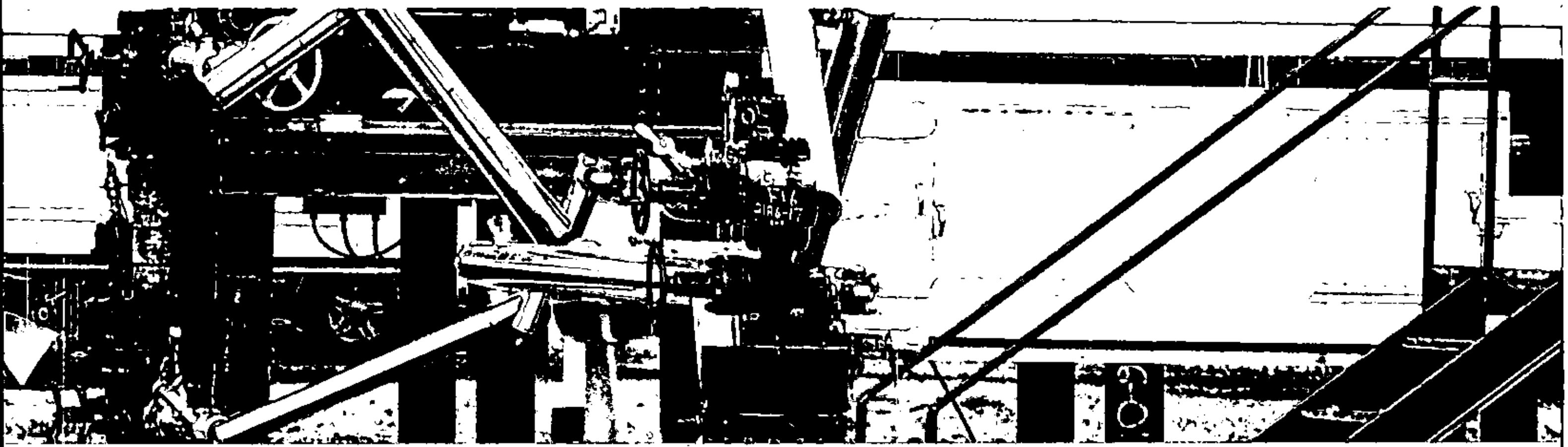
2006 Production (boe/day)

Western Canada Conventional	170,900
Heavy Oil	108,100
East Coast	68,500
International	12,200
Total	359,700 boe/day

Annual Average Production
(mboe/day)



Record production and strong commodity prices created unprecedented earnings in Husky's upstream operations.



Overview

WESTERN CANADA CONVENTIONAL

By targeting gas exploration in the Foothills, Deep Basin and Northern region, developing tight gas and coal bed methane, and applying technology to increase reservoir recovery, Husky will continue to maintain production levels that are expected to generate good returns and strong cash flow.

HEAVY OIL

With 40 years of experience, daily production exceeding 100,000 barrels per day, an extensive midstream and downstream infrastructure and enhanced oil recovery technologies, Husky will continue to be a leader in heavy oil.

CANADA'S EAST COAST

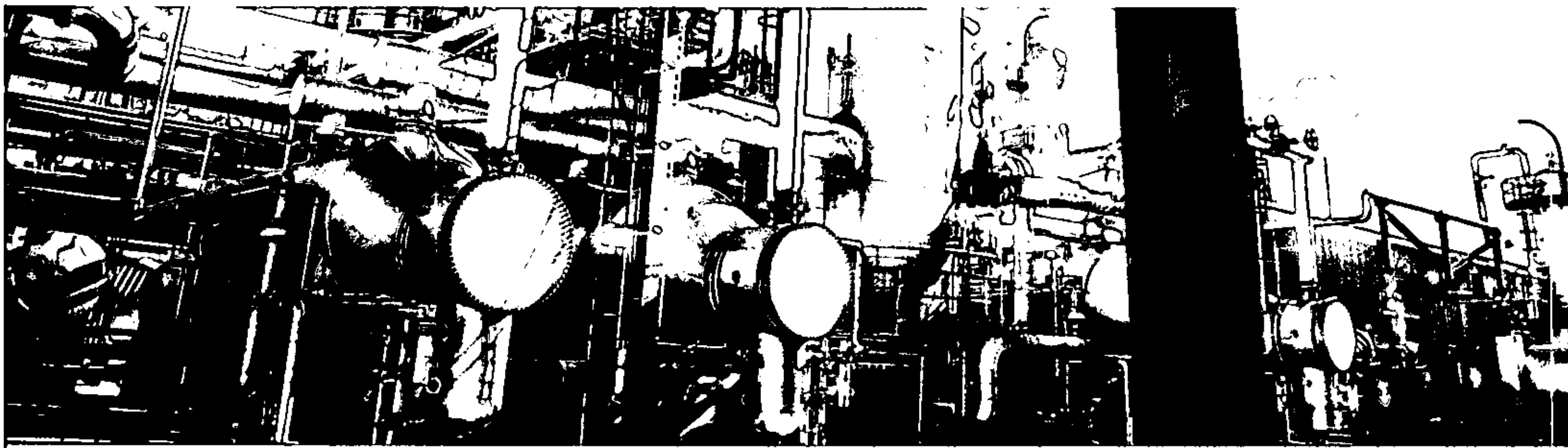
The success of the White Rose development and Husky's leading position offshore Canada's East Coast ensures the delivery of short- and long-term oil and gas production growth.

INTERNATIONAL

Husky's existing Wenchang production, Liwan discovery, proposed Madura development and extensive holdings offshore China and Indonesia provide a strong platform for future growth.

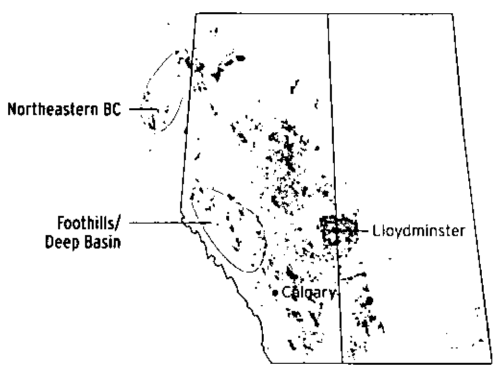
Proved Reserves (mboe)
(at December 31, 2006)

Western Canada Conventional	610,000
Heavy Oil	213,000
East Coast	107,000
International	14,000
Subtotal	944,000 mboe
Oil Sands	60,000
Total	1,004,000 mboe



Western Canada Conventional

Husky's strategy of drilling low-risk shallow gas prospects and applying enhanced oil recovery technologies using the Company's existing infrastructure can increase field production and generate good returns.



WESTERN CANADA CONVENTIONAL OIL & GAS ASSETS

- *Average working interest: 90%*
- *2006 average daily production:*
  - *Light oil and NGL: 30 mbbls/day*
  - *Medium oil: 29 mbbls/day*
  - *Natural gas: 672 mmcf/day*
- *Proved plus probable natural gas reserves: 2,533 bcf*
- *Proved plus probable oil and NGL reserves: 321 mmbbls*
- *Oil and gas landholdings: 7.2 million acres*

OUTLOOK

- *Achieve reserve replacement over 100%*
- *Seek out opportunities for coal bed methane and enhanced recovery technologies*
- *Maintain an average reinvestment ratio of 60%*
- *Focus on controlling capital and operating costs*
- *Emphasize health, safety and environmental performance*

PRODUCTION

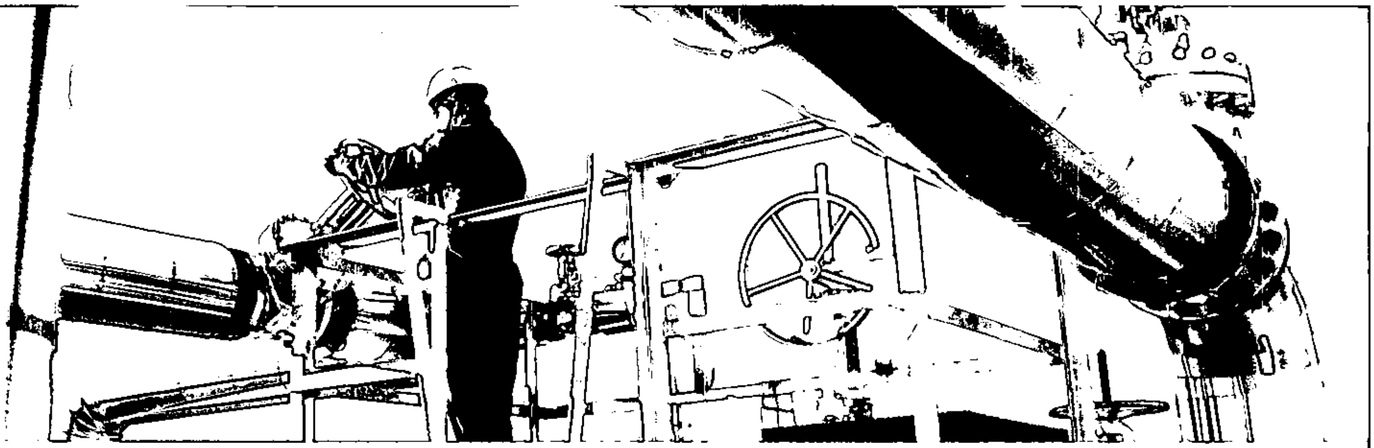
During 2006, Husky implemented an alkaline surfactant polymer (ASP) enhanced oil recovery project to extend the production life of the Taber South Mannville B Pool to recover an additional 6.4 million barrels of proven plus probable reserves. The Crowsnest ASP enhanced oil recovery project scheduled for start-up in 2007 is anticipated to recover 4.2 million barrels of proven plus probable reserves.

During 2006, Husky increased production of CBM in East Central and Southern Alberta to 32 million cubic feet per day, and Ansell/ Galloway in Northwestern Alberta produced 34 million cubic feet per day of natural gas from the Cardium resource play.

EXPLORATION

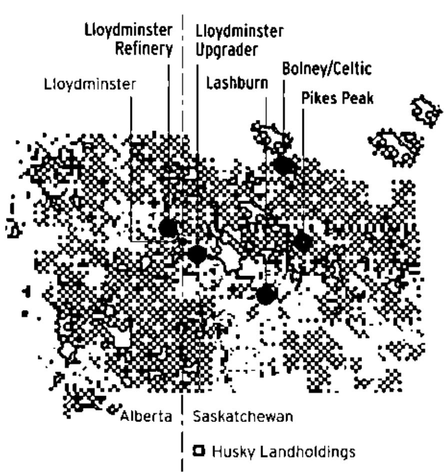
Husky and its partners made a hydrocarbon discovery at Stewart D-57 in the Central Mackenzie Valley, Northwest Territories. Testing showed a combined rate of five million cubic feet per day. This is in addition to the Summit Creek discovery made in 2004 which tested approximately 20 million cubic feet per day of natural gas, and more than 6,000 barrels per day of light oil and condensate.

The Company is also pursuing deeper gas prospects in British Columbia and the Alberta foothills. At Bullmoose, in northeastern British Columbia, the Company had several significant gas discoveries.



Heavy Oil

With a large resource base and an existing upgrader and refinery, Husky's integrated business in Lloydminster continues to demonstrate superior financial returns.



HEAVY OIL ASSETS

- *Large resource and land base*
- *Average working interest: 96%*
- *2006 average production: 108,100 bbls/day*
- *Proved plus probable reserves: 289 mmbbls*
- *Landholdings: 1.6 million acres*

OUTLOOK

- *Maintain production levels through exploitation of primary and thermal properties*
- *Progress new thermal project developments*
- *Develop and field test new enhanced oil recovery processes*
- *Focus on controlling capital and operating costs*
- *Emphasize health, safety and environmental performance*

DEVELOPMENT

During the past decade, Husky has generated growth in heavy oil through the development of its large land base. In 2006, the Company expanded its heavy oil production strategy to increase its focus on the development of thermal recovery projects and other enhanced recovery processes.

Husky plans to drill more than 600 oil and gas wells in the Lloydminster area during 2007 and progress thermal projects.

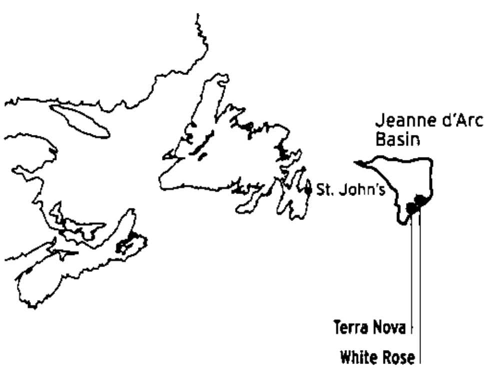
COST AND PRODUCTION

Husky's focus on financial discipline has helped to make its heavy oil operations successful. One of the technologies that has helped manage production costs is the use of single well monitoring. It has given the Company the ability to monitor the operations of hundreds of wells from a central facility where operators view production data, in real-time, to optimize production from wells and schedule carriers transporting crude from the field to central collection facilities.

An initiative is also underway to reduce fluid transportation costs through optimization of trucking resources, installation of flowlines where feasible and upgrades to water disposal facilities.

Canada's East Coast

Production from White Rose continues to exceed expectations. Its strong performance combined with recent delineation results and Husky's acreage position in the Jeanne d'Arc Basin provides for additional oil and gas growth opportunities.



CANADA'S EAST COAST

- *Working interest:*
  - *White Rose: 72.5%*
  - *Terra Nova: 12.51%*
- *2006 average daily production: 68,500 bbls/day*
- *Proved plus probable oil reserves: 186 mmbbls*

HOLDINGS

- *Significant discovery areas: 16*
- *Exploration licences: 12*
- *Production licences: 2*
- *Exploration acreage: more than 1.2 million acres*

OUTLOOK

White Rose
- *Further delineate White Rose oil and gas reserves*
- *Increase production capacity through completion of a seventh production well*
- *Progress White Rose satellite developments*

Terra Nova
- *Delineate Terra Nova Far East South oil and gas reserves*

Exploration
- *Drill Wild Rose and evaluate Primrose prospects*
- *Emphasize health, safety and environmental performance*

WHITE ROSE

The White Rose field has performed better than expected since achieving first oil in November 2005. Production capacity reached 125,000 barrels per day in 2006. Husky's focus in 2007 will be on safe and reliable operations, and increasing production subject to regulatory approval.

The Company made two significant discoveries near the producing White Rose field, in the Southwest and West Avalon pools. These discoveries have resulted in the addition of 138 million barrels of possible reserves to White Rose, which had combined proved, probable and possible reserves of 379 million barrels of light crude oil at the end of 2006.

During 2007, further delineation drilling will take place in the West Avalon pool to better define this resource.

Front-end engineering design studies will commence to develop the White Rose satellite fields.

TERRA NOVA

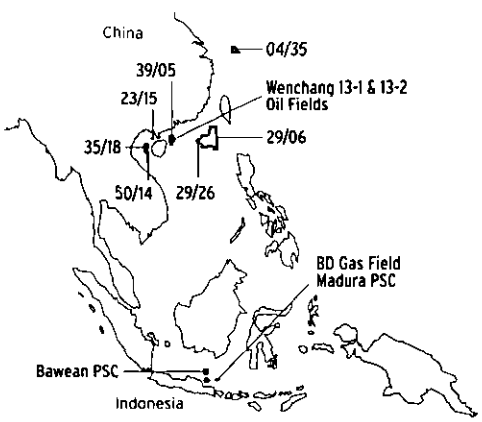
The Terra Nova field completed a major turnaround in 2006. As a result, production in 2007 is expected to increase significantly over the previous year. The Far East South area of the field will be further delineated in 2007.

EXPLORATION

Husky acquired three exploration blocks in the Jeanne d'Arc Basin and completed 3-D seismic programs on Exploration Licence 1067, containing the Wild Rose prospect, and Significant Discovery Licence 1011 in 2006. In 2007, the Company plans to drill an exploration well in the Wild Rose prospect.

International

Husky is increasing its international portfolio by expanding its production base and exploration activities in the South and East China Seas, and offshore Indonesia.



CHINA

Wenchang
- *Working interest: 40%*
- *2006 average production: 12,200 bbls/day*

Liwan 3-1-1 Discovery
- *Contingent resource: 4 to 6 tcf of natural gas*

Exploration Blocks
- *Exploration blocks: 7*
- *Area: 7.6 million acres*

INDONESIA

Madura Strait
- *Working interest: 100%*
- *Contingent resource:*
  - *Natural gas: 515 bcf*
  - *Liquids: 23 mmbbls*

East Bawean II
- *Area: 4,255 square kilometres*

OUTLOOK

China
- *Additional development drilling in Wenchang*
- *Continue exploration drilling of existing blocks*

Indonesia
- *Commercialize the Madura BD field*
- *Pursue exploration potential on Madura Strait and East Bawean Blocks*
- *Emphasize health, safety and environmental performance*

CHINA

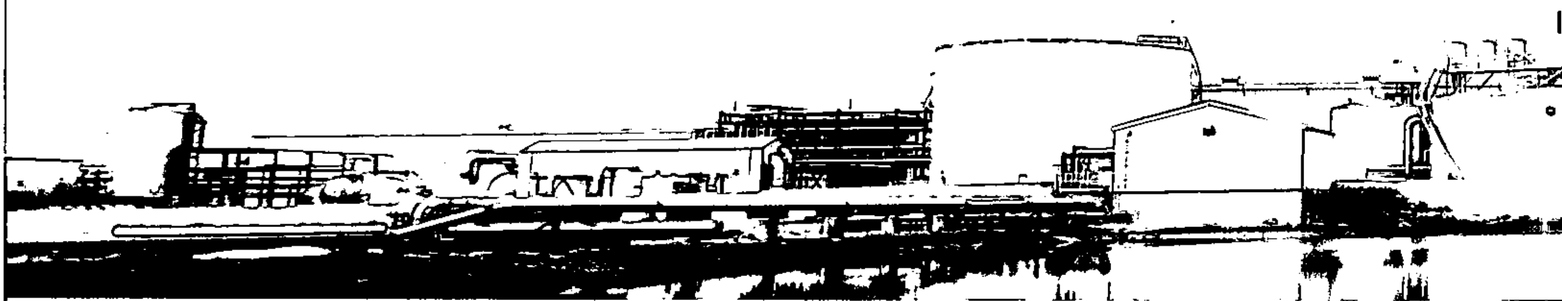
One of Husky's most significant discoveries during 2006 was a contingent resource of four to six trillion cubic feet of natural gas at Liwan 3-1-1 in Block 29/26 in the South China Sea. Seismic and delineation wells will be undertaken in 2007 and 2008 to evaluate the discovery. A deep water rig has been secured for a three-year term commencing in 2008.

Building on this discovery the Company signed three contracts with the China National Offshore Oil Corporation for exploration blocks in the South China Sea. Block 29/06, located in the Pearl Mouth Basin, is adjacent to Block 29/26 which contains the Liwan 3-1-1 discovery. Blocks 35/18 and 50/14 are located in the Ying Ge Hai Basin. With these acquisitions Husky is the largest foreign holder of blocks offshore China.

Production activities continue at Wenchang with three infill wells drilled and a liquefied petroleum gas facility brought on-stream during the year.

INDONESIA

During 2006, Husky was awarded the East Bawean II Block in the East Java Sea, increasing its Indonesian holdings to 1.7 million acres. At the Madura BD field the Company is pursuing a gas sales agreement and an extension of its Madura Strait production sharing contract. Development planning for the BD field is under way with first production expected in 2010.



Oil Sands

2006 Holdings

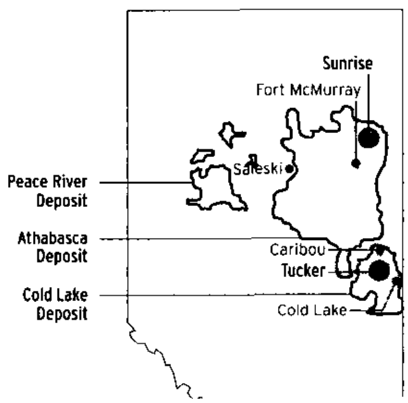
Total Acreage **510,890** acres

Discovered Resource **40,860** mmbbls

Oil Sands Leases

Lease	*Acreage (acres)*	*Discovered Resource (mmbbls)*
Tucker	10,080	1,270
Sunrise	57,635	10,600
Caribou Lake	35,840	2,500
Saleski	239,200	24,110
Others	168,135	2,380
Total	**510,890**	**40,860**

Husky has built a substantial and diverse asset base in the Canadian oil sands. Production at the Tucker Oil Sands Project, the Company's first oil sands development, commenced in November 2006.



TUCKER

- *Working interest: 100%*
- *Capital cost to first oil: $475 million*
- *Steam injection: August 2006*
- *First oil: November 2006*
- *Proved reserves: 60 mmbbls*
- *Probable reserves: 112 mmbbls*
- *Possible reserves: 180 mmbbls*
- *Peak production: 30,000+ bbls/day*

SUNRISE

- *Working interest: 100%*
- *Probable reserves: 1.0 billion bbls*
- *Probable plus possible reserves: 3.2 billion bbls*
- *Peak production: 200,000 bbls/day*

OUTLOOK

Tucker
- *Ramp up production*
- *Reduce operating costs as steam oil ratios improve*

Sunrise
- *Complete front-end engineering and design*
- *Identify an appropriate downstream solution*

Caribou Lake
- *Seek regulatory approval for demonstration project*
- *Initiate front-end engineering and design*

Saleski
- *Select potential recovery processes for pilot project*

- *Emphasize health, safety and environmental performance*

TUCKER

At the Tucker Oil Sands Project, 30 kilometres northwest of Cold Lake, Alberta, first steam was achieved in August followed by first oil in November. Peak production of more than 30,000 barrels per day is anticipated during its 35-year life. Production from Tucker is upgraded at Husky's heavy oil upgrader in nearby Lloydminster, Saskatchewan.

SUNRISE

Conceptual engineering work was completed for the Sunrise Oil Sands Project, 60 kilometres northeast of Fort McMurray, Alberta. Front-end engineering design has commenced and is targeted for completion by the third quarter of 2007. Husky is reviewing downstream alternatives including upgrading, refining, transportation and marketing.

CARIBOU LAKE

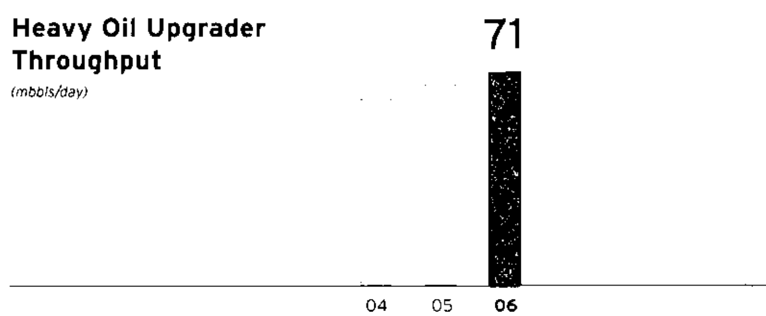
In 2006 Husky submitted a development application to regulators for a demonstration project of 10,000 barrels per day at Caribou Lake. Front-end engineering design will be initiated during 2007 in anticipation of regulatory approval.

SALESKI

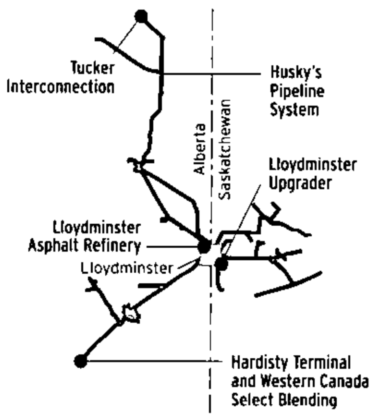
During 2006, Husky acquired 84,320 acres of leases increasing its land holdings in the Saleski area of northern Alberta to 239,200 acres. In 2007, the Company plans to identify potential recovery processes for a pilot project.

2006 Results

Heavy Oil Upgrader	Upgrader Throughput	71,000 bbls/day
Commodity Marketing	2006 Volumes	1,000 mboe/day
Facilities and New Ventures	Hardisty Pipeline Volumes	475,000 bbls/day



Husky's midstream assets are structured to optimize upstream operations and minimize cash flow volatility. Assets include a heavy oil upgrader, pipelines, electricity generation, and oil and gas storage.



FACILITIES

- *Upgrader throughput: 77,000 bbls/day*
- *Pipeline system: 2,087 km*
- *Pipeline throughput: 475,000 bbls/day*
- *Natural gas storage: 33.5 bcf*
- *Cogeneration:*
  - *215 MW facility, Lloydminster, SK: 50% ownership interest*
  - *90 MW facility, Rainbow Lake, AB: 50% ownership interest*

OUTLOOK

- *Heavy oil upgrader:*
  - *Undertake plant turnaround in Q2*
  - *Complete debottlenecking project*
  - *Complete FEED study to expand capacity to 150,000 bbls/day*
- *Complete mainline pipeline expansion*
- *Increase commodity sales from conventional production growth*
- *Emphasize health, safety and environmental performance*

HEAVY OIL UPGRADER

The heavy oil upgrader at Lloydminster, Saskatchewan is connected by pipeline to Husky's heavy oil and Tucker bitumen production. It processes heavy oil feedstock into premium quality synthetic crude oil for refiners.

Work continued during the year on a debottlenecking project to increase throughput capacity from 77,000 to 82,000 barrels per day for completion in 2007. Husky initiated front-end engineering for a potential expansion of the upgrader's throughput capacity to 150,000 barrels per day. During the year, upgrader employees achieved 4.9 million person-hours worked without any lost-time accidents.

FACILITIES AND NEW VENTURES

Husky's pipeline system has become a core business that carries crude oil from Husky and third party facilities in northeast Alberta and northwest Saskatchewan to its Lloydminster refinery and heavy oil upgrader. Remaining crude and synthetic oil are shipped to the Company's terminal at Hardisty, Alberta.

The Hardisty pipeline terminal injects Husky and third party crude oil streams into three transcontinental trunk pipelines. A 23 percent increase in the terminal's storage capacity was added ahead of schedule and below budget during 2006.

COMMODITY MARKETING

During 2006, new sales and financial records were set for Commodity Marketing. Crude oil, natural gas, natural gas liquids, sulphur and petroleum coke volumes managed exceeded one million barrels of oil equivalent per day.

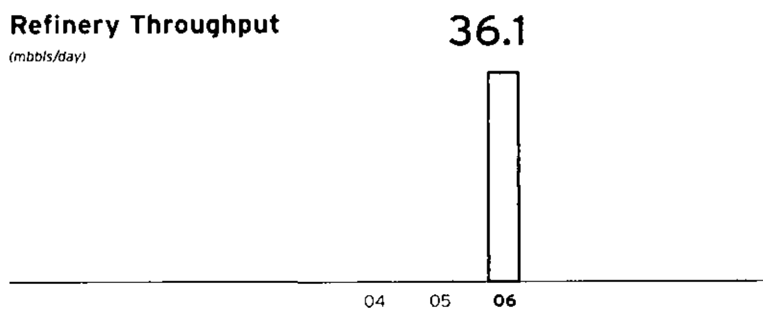
The Company's natural gas storage operations are becoming a core business. At the end of 2006, Husky had 33.5 billion cubic feet of storage capacity in both owned and contracted facilities.

Refined Products

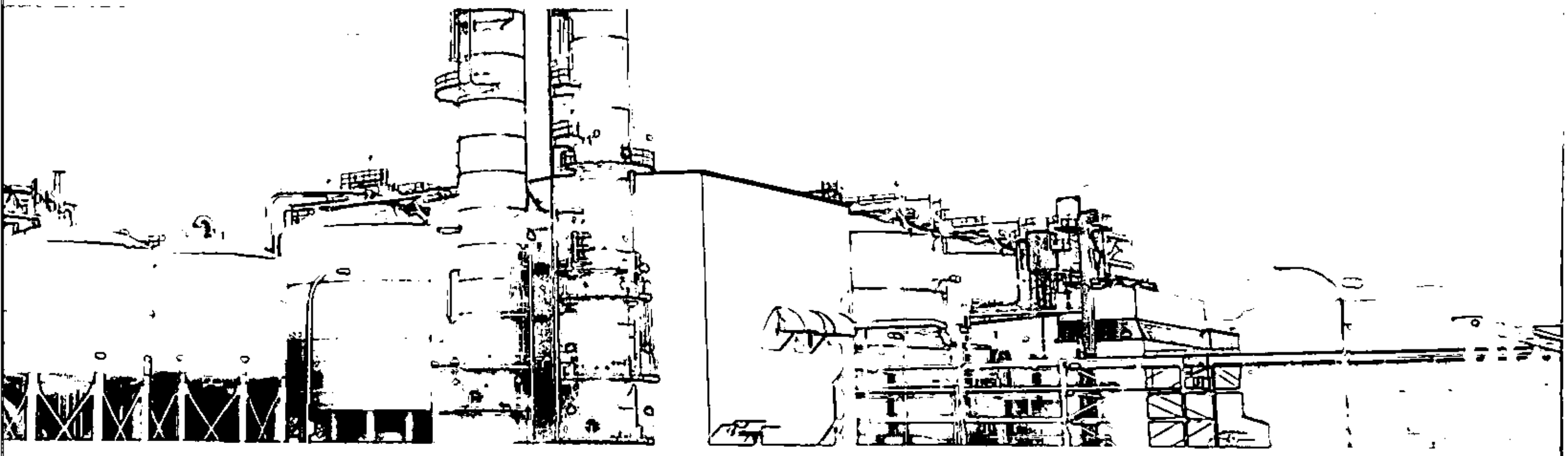
2006 Results

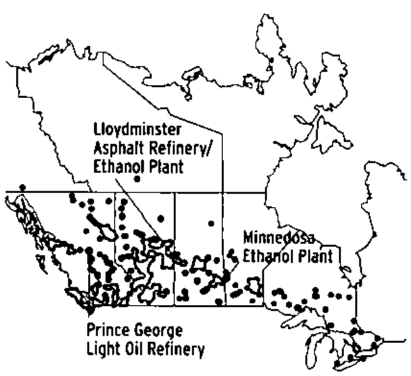
Prince George Refinery	Throughput 9,000 bbls/day
Lloydminster Asphalt Refinery	Throughput 27,100 bbls/day
Asphalt Marketing	Sales Volumes 23,400 bbls/day
Retail Marketing	Total Outlets 500+

Refinery Throughput
(mbbls/day)



Husky produces and retails low-sulphur gasoline and diesel, and environmentally friendly ethanol-blended "Mother Nature's Fuel."





PRODUCTION FACILITIES

- *Emulsion Plants/Asphalt Terminals: 8*
- *Prince George Light Oil Refinery: 12,000 bbls/day*
- *Lloydminster Asphalt Refinery: 28,000 bbls/day*
- *Lloydminster Ethanol Plant: 130 million litres/year*
- *Minnedosa Ethanol Plant: 10 million litres/year*

OUTLOOK

- *Expand ethanol business*
- *Optimize production at the Lloydminster Ethanol Plant*
- *Complete construction of the Minnedosa Ethanol Plant*
- *Increase sales volume per retail outlet by 3.5 percent*
- *Grow ancillary income by 10 percent over 2006*
- *Emphasize health, safety and environmental performance*

RETAIL MARKETING

Husky markets fuels through a network of more than 500 Husky and Mohawk retail outlets, travel centres and bulk distributors from British Columbia to Ontario. Since 2000, annual throughput per station increased 38 percent to 4.75 million litres in 2006. Growth in ancillary income from retail outlets increased 10 percent per year from 2002 to 2006.

PRINCE GEORGE LIGHT OIL REFINERY

The Prince George Light Oil Refinery produces low-sulphur gasoline and diesel fuels, butane and propane mix, and heavy fuel oil. The Clean Fuels Project to reduce sulphur content in gasoline and diesel fuels, and a related refinery expansion were completed in 2006, increasing refinery throughput capacity 20 percent to 12,000 barrels per day.

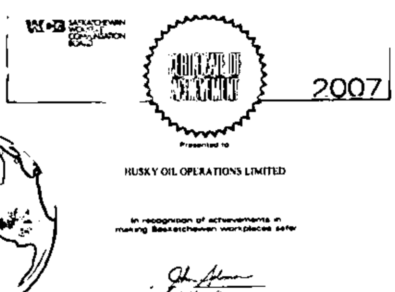
ASPHALT REFINING AND MARKETING

The Lloydminster Asphalt Refinery produces high quality asphalt products for road construction and maintenance, building materials, locomotive blendstock and specialized oil field products. In 2006, the refinery processed a record 27,100 barrels per day and shipped 807,400 cubic metres of asphalt to customers across North America.

ETHANOL

The completion of Husky's 130-million litre per year wheat-based Lloydminster Ethanol Plant and manufacturing of ethanol for ethanol-blended gasoline demonstrates the Company's commitment to helping motorists reduce greenhouse gas emissions. Husky will become one of Western Canada's largest buyers of wheat with the expansion of the Minnedosa, Manitoba ethanol plant to 130 million litres in late 2007.

HSE and Social Responsibility



Husky contributed $335,000 towards the purchase of a CT scanner for the Lloydminster Hospital.

The Saskatchewan Workers' Compensation Board recognized Husky's heavy oil upgrader for its injury prevention and safety practices.

Husky was recognized by the Canadian Renewable Fuels Association for increasing the production of ethanol.

HEALTH AND SAFETY

Health and safety in the workplace is the responsibility of all employees and contractors at Husky. In 2006, the Company implemented a safe work practices program for contractors at work sites. Employees at the Lloydminster heavy oil upgrader achieved almost five million working hours (approximately 10 years) without an employee lost time accident. This achievement has resulted in the Company receiving the lowest workers' compensation premium in Saskatchewan.

ENVIRONMENT

Husky's environmental stewardship program was instrumental in the Company receiving 471 reclamation certificates and releases from regulators in 2006. The program includes consulting with the public, documenting stakeholder commitments, establishing clarity with regulators, and monitoring and addressing site-specific environmental issues prior to constructing and operating a facility. At the end of the facility's life remediation is undertaken to minimize future impacts.

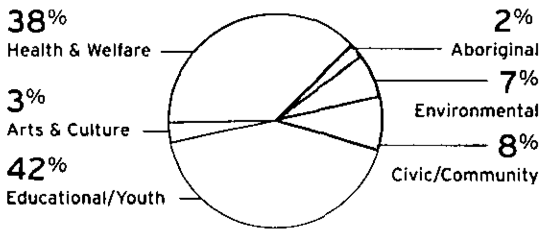
COMMUNITY INVESTMENT

The Company's community investment program focuses on supporting long-term benefits in the communities where it does business. Husky places a high value on education, and believes that advancing education is an investment in the future of society. During 2006, Husky donated over $5 million to more than 500 charitable organizations. Under its program that matches employee donations, more than $750,000 was contributed to 56 charities.

ABORIGINAL AFFAIRS

Husky is committed to meaningful and productive consultation with Aboriginal communities. This is demonstrated through Husky-sponsored programs that encourage education, support health and wellness, and directly foster economic development.

2006 Charitable Donations



Husky is committed to growing in a socially responsible manner by focusing on health and safety initiatives, environmental management and community participation.

2006 Performance

Health and Safety	No lost time accidents at Upgrader 10 years
Environmental Stewardship	Reclamation certificates 471 received
Community Investment	Commitments $5 million

Whooping crane (Husky Endangered Species Program)

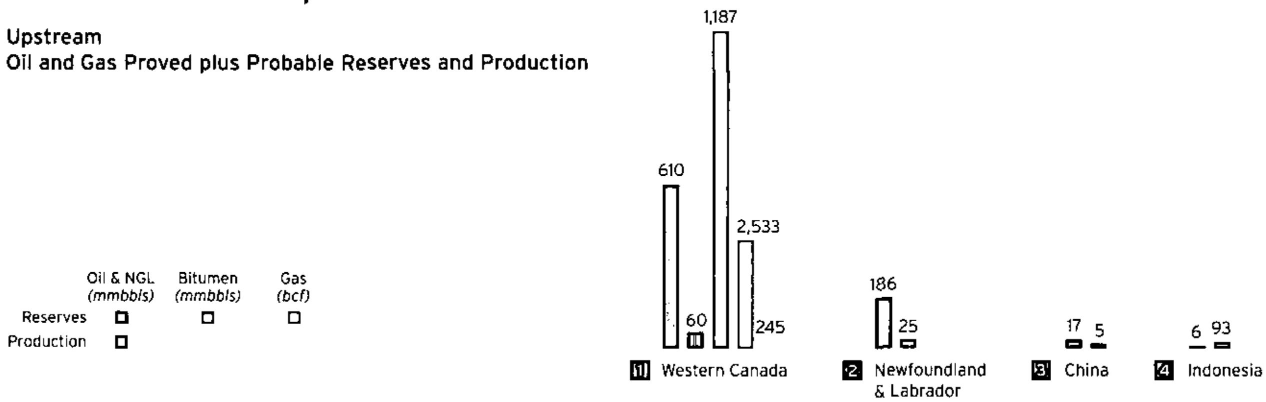
Management's Discussion and Analysis

February 26, 2007

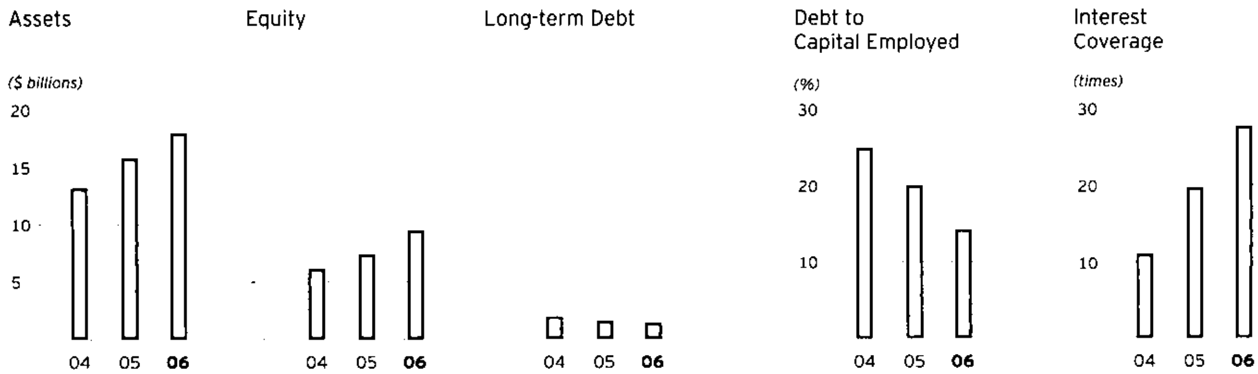
Table of Contents

1.0 Financial and Operational Overview

Upstream
Oil and Gas Proved plus Probable Reserves and Production



Financial Position



1.1 HUSKY'S BUSINESSES

Husky is an energy and energy related enterprise operating in three integrated business segments:

Upstream

Exploration and development of crude oil, bitumen and natural gas in:

- the Western Canada Sedimentary Basin;
- the oil sands region of Alberta;
- the Jeanne d'Arc Basin off the East Coast of Canada;
- the Mackenzie Valley in the Northwest Territories;
- the South China Sea and the East China Sea; and
- the Madura Strait and north east Java Sea, offshore Indonesia.

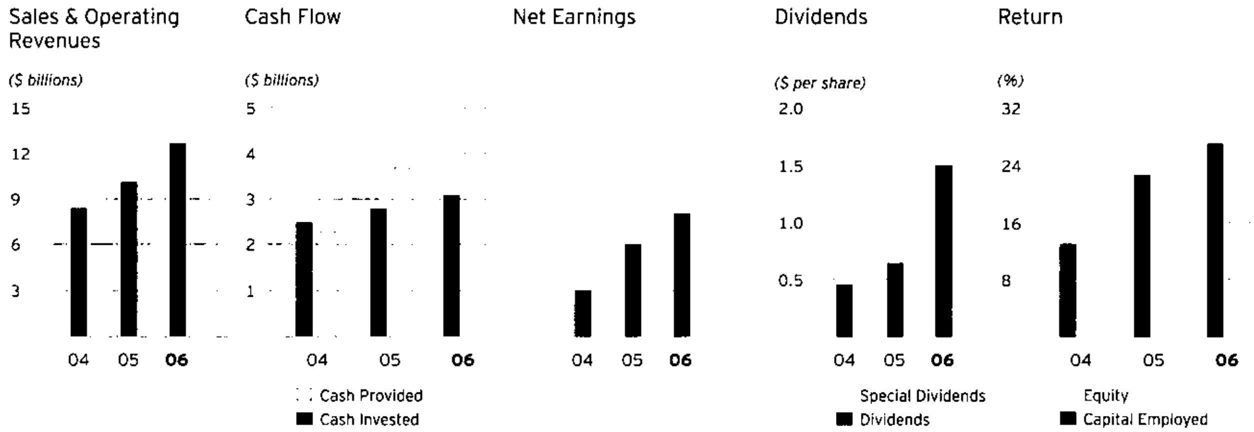
Midstream

- heavy oil upgrader located at Lloydminster, Saskatchewan with a current throughput capacity of approximately 76 mbbls/day yielding 65 mbbls/day of synthetic crude oil and 11 mbbls/day of diluent;
- pipeline systems with combined capacity in excess of 500 mbbls/day in the heavy oil producing regions between Cold Lake, Alberta south through Lloydminster to Hardisty, Alberta; and
- crude oil and natural gas storage facilities, cogeneration and commodity marketing.

Refined Products

- 505 retail and wholesale locations from the West Coast of Canada to the eastern border of Ontario;
- a recently upgraded 12 mbbls/day full slate refinery in Prince George, British Columbia;
- a 28 mbbls/day asphalt refinery in Lloydminster, Alberta and a Western Canada asphalt marketing and distribution system; and
- ethanol plants at Lloydminster, Saskatchewan and Minnedosa, Manitoba with current combined annual capacity of 140 million litres. The Minnedosa, Manitoba ethanol plant expansion in 2007 will increase combined annual capacity to 260 million litres.

Financial Performance



1.2 FINANCIAL OVERVIEW

See Financial Position and Financial Performance graphs above.

1.3 SELECTED ANNUAL INFORMATION

($ millions, except where indicated)	**2006**	2005	2004
Sales and operating revenues, net of royalties	**$12,664**	$10,245	$ 8,440
Segmented earnings			
Upstream	**$ 2,295**	$ 1,524	$ 713
Midstream	**482**	495	240
Refined Products	**106**	82	41
Corporate and eliminations	**(157)**	(98)	12
Net earnings	**$ 2,726**	$ 2,003	$ 1,006
Per share			
Basic and diluted	**$ 6.43**	$ 4.72	$ 2.37
Dividends per common share	**$ 1.50**	$ 0.65	$ 0.46
Special dividend per common share	**$ –**	$ 1.00	$ 0.54
Total assets	**$17,933**	$15,716	$13,233
Long-term debt excluding current portion	**$ 1,511**	$ 1,612	$ 2,047
Return on equity *(percent)*	**31.8**	29.2	17.0
Return on average capital employed *(percent)*	**27.0**	22.8	13.0

1.4 SELECTED QUARTERLY INFORMATION

	2006				2005			
($ millions, except where indicated)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties	**$ 3,084**	**$ 3,436**	**$ 3,040**	**$ 3,104**	$ 3,207	$ 2,594	$ 2,350	$ 2,094
Net earnings	**542**	**682**	**978**	**524**	669	556	394	384
Per share								
Basic and diluted	**1.28**	**1.61**	**2.31**	**1.24**	1.58	1.31	0.93	0.91
Cash flow from operations	**1,207**	**1,224**	**1,103**	**967**	1,197	944	828	816
Per share								
Basic and diluted	**2.84**	**2.88**	**2.60**	**2.28**	2.82	2.23	1.95	1.93
Share price								
High	**80.45**	**83.00**	**75.64**	**74.50**	65.79	69.95	50.75	40.49
Low	**66.20**	**66.31**	**58.00**	**59.63**	50.50	47.37	35.12	32.30
Close (end of period)	**78.04**	**71.96**	**70.06**	**70.65**	59.00	64.57	48.73	36.33
Shares traded *(thousands)*	**41,889**	**30,786**	**39,674**	**39,543**	38,731	34,521	46,988	46,370
Dividends declared per common share	**0.50**	**0.50**	**0.25**	**0.25**	0.25	0.14	0.14	0.12
Special dividend per common share	**–**	**–**	**–**	**–**	1.00	–	–	–
Weighted average number of common shares outstanding *(thousands)*								
Basic and diluted	**424,264**	**424,234**	**424,179**	**424,147**	424,120	424,049	423,891	423,791

1.5 MAJOR EVENTS IN 2006

East Coast

completed sixth production well in November 2006, which increased White Rose productive capacity to approximately 125 mbbls/day. During December 2006 total field production at White Rose averaged 116 mbbls/day (Husky's working interest share was 85 mbbls/day), an increase of 17% from November; and

increased our holdings in the Jeanne d'Arc Basin with the acquisition of two exploration licences totalling 38,585 acres and increased our working interest in Significant Discovery Licences 1040 and 1008 with a farm-in.

Oil Sands

completed construction of the 100% working interest steam-assisted gravity drainage ("SAGD") in-situ Tucker Oil Sands project. With a design rate capacity of 30 mbbls/day of bitumen, the project will be ramped up to its capacity plateau over the next two years. Proved reserves at December 31, 2006 were 60 mmbbls of bitumen; and

increased our Saleski, Alberta oil sands holdings to 239,200 acres.

Ethanol

completed construction of Lloydminster ethanol plant. With a design rate capacity of 130 million litres of ethanol per year, the plant will participate in providing ethanol blending feedstock for the emerging market for ethanol blended gasoline.

Refining

completed the second phase of the Prince George refinery clean fuels project to produce low-sulphur diesel fuel and gasoline and increased productive capacity to 12 mbbls/day.

International

increased our holdings in the South China Sea with an award of three exploration blocks totalling 16,871 square kilometres;

natural gas discovery in the South China Sea at Liwan 3-1-1; and

increased our holdings in the north east Java Sea with the East Bawean II block.

Corporate

redeemed the 8.45% senior secured bonds, due 2012, which had an outstanding balance of U.S. $85 million;

received an improved credit rating from Standard and Poor's Rating Service to BBB+ with a stable outlook; and

renewed the shelf prospectus, which facilitates the issue of up to U.S. $1 billion of debt securities in the U.S. capital markets until October 2008.

2.0 Capability to Deliver Results

Our strategic plans involve a number of large initiatives in our upstream business that are expected to provide the means to achieve our corporate goals. We expect to reach our goals without compromising our financial capacity and flexibility. We expect to maintain our workforce through increasing investment in training, mentoring, succession and retention programs.

2.1 UPSTREAM

Upstream business strengths include:

- a large base of producing properties in Western Canada that generally respond well to increasingly sophisticated exploitation techniques and, we expect, will continue to provide a large proportion of cash flow necessary to undertake current and future major growth projects;
- significant natural gas potential in the deep basin, foothills and northwest plains;
- a dominant presence and extensive experience in the heavy oil producing areas in the Lloydminster region of Alberta and Saskatchewan;
- a recently developed SAGD oil sands project and substantial long-term growth potential in a number of the oil sands regions of Alberta;
- two major offshore producing oil fields in the Jeanne d'Arc Basin off the East Coast of Canada, combined with a large portfolio of significant discovery licences and exploration licences;
- significant opportunities to tie-back production from satellite fields to the existing White Rose production;
- increasing experience and number of developable projects and potential prospects in Southeast Asia; and
- the financial capacity to enhance our portfolio value through acquisitions.

Upstream business will be challenged by:

- increasing costs driven by the high level of oil and gas industry activity;
- labour market skills shortages;
- a highly competitive environment for materials, equipment and services;
- increasing difficulty and cost of managing the natural production declines of our properties in the Western Canada Sedimentary Basin;
- susceptibility of large complex operations to reliability issues and significant loss of cash flow during down-time;
- increasing activities of opposing special interest groups;
- increasing political pressure to implement fiscal regimes that might divert material cash flow available for investment; and
- increasing environmental issues that may delay, prevent or increase the costs of oil and gas development.

2.2 MIDSTREAM

Midstream business strengths include:

- a modern, reliable heavy oil upgrading facility located in the Lloydminster heavy oil producing region, currently completing a number of debottlenecking projects and capable of major expansion;
- reliable heavy oil pipeline systems in the Lloydminster heavy oil producing region currently being expanded;
- participation in electrical/thermal cogeneration that can be utilized in our plant operations; and
- a commodity marketer capable of acting as a market balancer to both customer and supplier.

Midstream business will be challenged by:

- increasingly heavier crude feedstock requiring expansion and modification of our upgrader; and
- competition for pipeline capacity in heavy crude oil producing regions.

2.3 REFINED PRODUCTS

Refined products business strengths include:

- an established niche market with prime marketing outlet locations and strategic land position;
- recently upgraded low sulphur gasoline and diesel fuel refinery in north central British Columbia;
- growing economies of scale for our increasing ethanol production;
- position as largest manufacturer of paving asphalt in Western Canada; and
- modern asphalt manufacturing facilities at Lloydminster, Alberta.

Refined products business will be challenged by:

- limited access to refining facilities sufficient to supply our refined product requirements;
- increased competition as motor fuel and related products are increasingly being offered by other industry retailers; and
- higher asphalt distribution costs as a result of plant locations and lack of asphalt distribution network in the United States and Eastern Canada.

2.4 KEY PERFORMANCE DRIVERS AND MEASURES

In order to achieve our mission of maximizing returns to our shareholders in a socially responsible manner we must, in the medium and long-term:

- find and develop proved reserves of crude oil and natural gas at a cost that is competitive with the industry; and
- acquire developed and undeveloped properties which complement our portfolio and provide enhanced potential for future sustainable growth.

In the short-term we must:

- competitively optimize production through effective exploitation techniques;
- make selective acquisitions and divestitures;
- maintain costs among the industry's lowest cost quartile performers;
- manage our operations in a safe and environmentally responsible manner;
- continue to proceed with the development of our major expansion projects in the Jeanne d'Arc Basin, the Alberta oil sands, the Madura Strait natural gas and NGL project;
- delineate our oil discovery in the Mackenzie Valley region of the Northwest Territories;
- delineate our natural gas prospect in the South China Sea; and
- complete the optimization and expansion assessment of the Lloydminster Upgrader.

In addition to the metrics presented by financial statements, which are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), we prepare a number of additional performance indicators. Although these metrics may not be comparable with other companies, they are comparable from period to period within Husky and are important decision making tools for management.

The overall corporate performance metrics that we monitor with respect to achieving return to our shareholders' goals are return on equity and return on average capital employed and are in Section 1.3, "Selected Annual Information."

The following table shows the total shareholder return compared with the Standard and Poor's and the Toronto Stock Exchange energy and composite indices.

(percent)	Husky Common Shares	S&P/TSX Energy Index	S&P/TSX Composite Index
2002	0.00	(14.00)	11.00
2003	43.00	24.42	24.32
2004	45.45	12.15	28.26
2005	72.12	22.50	59.89
2006	32.40	14.59	1.14
Five year average	36.51	10.93	23.47
Five year return	374.00	68.00	187.00

Revenue Performance

Our revenues are sensitive primarily to changes in the commodity prices we receive for the products we sell, particularly for our production of crude oil and natural gas. Changes in these prices are caused by many factors that are outside of our control. As a result we must focus on increasing the volume of the commodities that we produce. All plans to increase production must be expected to achieve minimum rates of return before capital is allocated. Production is subsequently measured against expected results.

Cost Performance

Cost of sales and operating expenses comprise many components such as energy and crude oil feedstock costs for refining and upgrading operations and refined product purchase costs for the majority of our refined products marketing operations. Our focus is on optimizing our costs to achieve a competitive position in the industry.

Capital Performance

Before capital is allocated to a project, its expected benefits must achieve an appropriate rate of return. Capital expenditures are monitored on a project-by-project basis and requirements for capital supplements are approved only by senior executive management. Upstream capital, which generally accounts for the majority of our capital budget, is monitored in detail to ensure that it achieves the desired result, which is to increase production, optimize operating expenses or increase reserves.

People Performance

We continually monitor the effectiveness of our work environment and corporate culture. To help us foster the development of a value-based culture, we monitor attrition rates as well as the results of exit interviews and training statistics. We facilitate and maintain a workplace that is respectful, inclusive, safe and socially responsible. We also keep informed of industry trends to ensure that we are well placed in the market with respect to being an employer of choice.

Health, Safety and Environmental Performance

We monitor all recordable accidents and all reportable environmental events that involve our operations. In addition, we conduct root cause investigations subsequent to events and regular audits to ensure full compliance.

2.5 THE BUSINESS ENVIRONMENT IN 2006

Our financial results are significantly influenced by the global and domestic business and operating environment. Some factors are entirely beyond our control and others can be strategically managed. Salient factors include:

- crude oil and natural gas prices;
- the price differential between light and discounted heavy crude oil and demand related to various crude oil qualities;
- the cost to find, develop, produce and deliver crude oil and natural gas;
- the availability of new proved reserves of oil and gas, sourced from exploration, improved recovery and acquisitions;
- potential actions of governments and regulatory authorities in the jurisdictions where we have operations;
- prevailing climatic conditions in our operating and marketing locations; and
- the exchange rate between the Canadian and U.S. dollar.

Average Benchmark Prices and U.S. Exchange Rate

		2006	2005	2004
WTI crude oil	*(U.S. $/bbl)*	**66.22**	56.56	41.40
Brent crude oil	*(U.S. $/bbl)*	**65.14**	54.38	38.21
Canadian par light crude 0.3% sulphur	*($/bbl)*	**73.29**	69.28	52.91
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**39.92**	31.07	28.75
NYMEX natural gas	*(U.S. $/mmbtu)*	**7.23**	8.62	6.14
NIT natural gas	*($/GJ)*	**6.62**	8.04	6.44
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**22.00**	21.01	13.65
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.882**	0.826	0.769

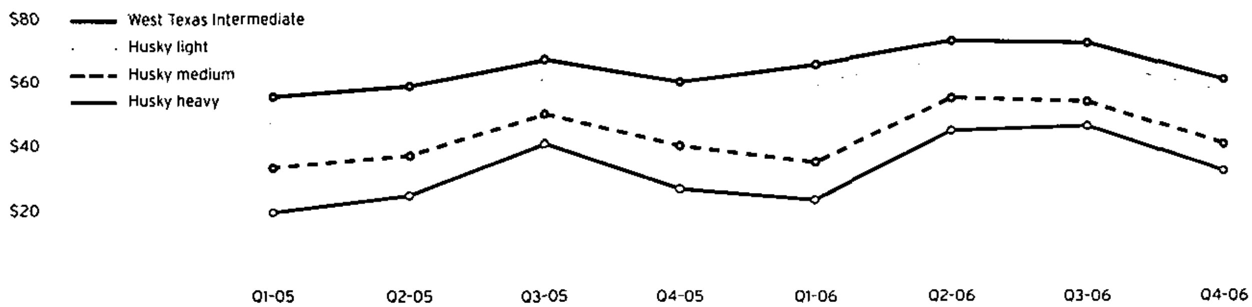
Profitability is largely determined by the prices realized for crude oil and natural gas. All of our crude oil production and the majority of our natural gas production receives the prevailing market price. The price for crude oil is determined largely by global factors and is beyond our control. The price for natural gas is determined more by the environment in North America, since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. The price of natural gas, within its market area, is also subject to the supply and demand equation. Weather conditions may also exert a dramatic effect on short-term supply and demand.

The global decline in the supply of light crude oil has increased prices in line with demand from refineries that are limited to a light crude oil feedstock. The price of heavy crude oil has historically traded at a discount since light crude oil produces a higher yield of light refined products such as gasoline and heavy crude oil requires more complex refining processes for cracking, desulphurization and coking. Although the differential between light and heavy crude oil typically widens when light crude oil prices increase, heavy crude oil prices have increased as well. The higher prices for heavy crude oil encourage increased development and production of heavy oil consequently increasing the supply in the market. The market often becomes over supplied with heavy crude oil and in turn light/heavy differentials widen at the expense of heavy oil prices. Most refiners need higher discounts to use heavy oil to maintain refining margins. Our upgrader, which is located in the Lloydminster heavy oil region, produces a synthetic light crude oil from heavy oil feedstock that will yield a high proportion of high value light products from light oil refining processes.

The majority of our crude oil and natural gas production is marketed in North America.

Crude Oil

WTI and Husky Average Crude Oil Prices (US$/bbl)

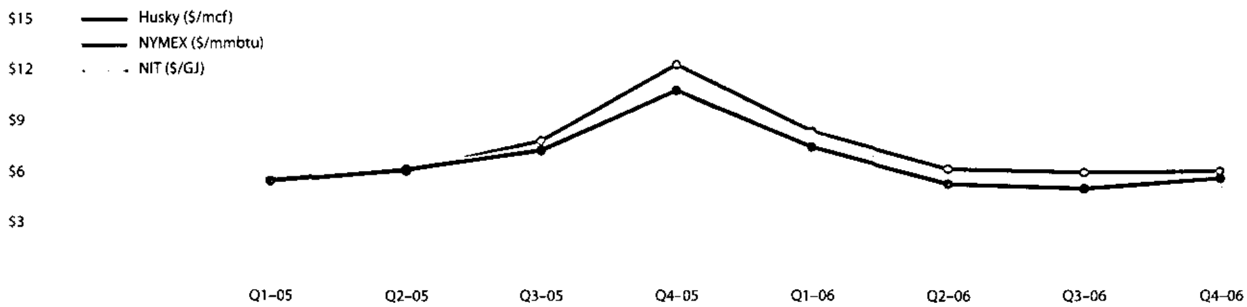


In 2006, the main benchmark crude oil, West Texas Intermediate, repeated the same pattern as it did in 2005, but at a higher price level. That pattern saw prices run up to the beginning of the hurricane season around August/September, reaching U.S. $77 and then decline to the end of the year when hurricanes did not cause any damage to the oil and gas infrastructure in the U.S. Gulf of Mexico. In addition, during 2006 crude oil prices fell much faster, leveling below U.S. $60 /bbl by mid-October, a time when crude oil inventories in the United States reached 114% of five-year averages.

The high crude oil inventories tended to mitigate the effect of any other threatened supply disruption such as the continued social unrest in Nigeria and Iraq. Prices rose only briefly after cold weather arrived in December.

Natural Gas

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices (US$)



Natural gas prices declined during the first quarter of 2006 from January delivery contract highs over U.S. $14/mmbtu, which resulted from devastating hurricane damage to oil and gas infrastructure along the Gulf Coast, to near month contracts below U.S. $7/mmbtu at the end of March. Natural gas prices continued to fluctuate in the U.S. $7/mmbtu to U.S. $6/mmbtu range until August, when widespread hot weather increased cooling demand and induced a short lived spike to the U.S. $8/mmbtu range. Prices then fell to just above U.S. $4/mmbtu as the Gulf of Mexico remained free of significant tropical storm activity and cooler temperatures prevailed. During the fourth quarter, natural gas prices first rose as a result of both hot weather in the southern states and cold weather in the north, then fell through December as temperatures moderated and natural gas inventories remained markedly higher than five-year averages.

Sensitivities by Segment for 2006 Results

The following table is indicative of the relative annualized effect on pre-tax cash flow and net earnings from changes in certain key variables in 2006. In essence, the disclosure shows what the effect would have been on 2006 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2006. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

	2006 Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	*($/share)* [5]	*($ millions)*	*($/share)* [5]
Upstream and Midstream						
WTI benchmark crude oil price	$ 66.22	U.S. $1.00/bbl	90	0.21	60	0.14
NYMEX benchmark natural gas price [1]	$ 7.23	U.S. $0.20/mmbtu	37	0.09	24	0.06
WTI/Lloyd crude blend differential [2]	$ 22.00	U.S. $1.00/bbl	(30)	(0.07)	(20)	(0.05)
Exchange rate *(U.S. $ per Cdn $)* [3]	$ 0.882	U.S. $0.01	(69)	(0.16)	(47)	(0.11)
Refined Products						
Light oil margins	$ 0.04	Cdn $0.005/litre	16	0.04	11	0.02
Asphalt margins	$ 9.88	Cdn $1.00/bbl	9	0.02	6	0.01
Consolidated						
Year-end translation of U.S. $ debt *(U.S. $ per Cdn $)*	$ 0.858 [4]	U.S. $0.01			9	0.02

(1) Includes decrease in earnings related to natural gas consumption.
(2) Includes impact of upstream and upgrading operations only.
(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.
(4) U.S./Canadian dollar exchange rate at December 31, 2006.
(5) Based on December 31, 2006 common shares outstanding of 424.3 million.

3.0 Strategy

3.1 STRATEGIC IMPERATIVES

Strategic Objective and Measures

Our strategy is to continue exploiting our oil and gas asset base in the Western Canada Sedimentary Basin while expanding into large scale sustainable areas including the Alberta oil sands, Canada's East Coast and northern basins and highly prospective basins offshore Southeast Asia. In the global energy business environment, which has many risks, commodity prices being primary among them, we must maintain our financial discipline to successfully maintain this strategy.

Strategic Plans

Our ultimate success in achieving long-term objectives rests on the effective execution of a number of operational and financial strategies. In this regard we employ a planning process that provides critical consideration to our stated strategies and their possible outcomes.

Upstream Strategies

- manage declining production in Western Canada through field and facility optimization, increased multi-zone development, increased applications of enhanced oil recovery techniques, property consolidation, development of new core areas and exploitation of non-conventional natural gas reservoirs;
- continue to explore for liquid rich natural gas reserves in the less mature, high-impact but technically challenging areas in the foothills, deep basin and northern plains;
- continue with exploration in the Central Mackenzie Valley and complete delineation and evaluation of the Stewart Creek natural gas discovery in conjunction with the Summit Creek natural gas and liquids discovery 26 kilometres northwest of Stewart Creek;
- continued delineation and development of the White Rose area satellite prospects and on our portfolio of significant discovery licences off the East Coast and also continue to explore for oil and gas on our large portfolio of exploration licences in the Jeanne d'Arc Basin offshore Newfoundland and Labrador;
- expand the productive capacity of the *SeaRose FPSO* to 140 mbbls/day;
- continue to study development options for natural gas export from the Jeanne d'Arc Basin;
- continue to explore for oil and gas offshore China, delineate and evaluate the Liwan natural gas discovery on Block 29/26 in the Pearl River Mouth Basin;
- development of our Indonesian natural gas and NGL BD field in the East Java Sea and exploration on the Madura Strait and East Bawean II blocks;
- continue development of our large holdings in the Alberta oil sands area through in-situ recovery methods such as SAGD and other thermally based recovery techniques; and
- take advantage of acquisition opportunities to enhance our current core properties and create new ones.

Midstream Strategies

- continue to enhance performance of our upgrader and integrate the operation of the upgrader, asphalt refinery, cogeneration and ethanol facilities;
- complete front-end engineering design to expand the upgrader to 150 mbbls/day;
- further expansion and integration of pipelines and facilities;
- expand natural gas storage capacity; and
- develop an integrated CO_2 strategy.

Refined Products Strategies

- continue to integrate Lloydminster asphalt refinery output with the upgrader;
- expand ethanol production in Western Canada;
- continue to pursue initiatives that promote asphalt standards and thereby recognize Husky's asphalt quality; and
- increase throughput per outlet through technology, new products and services.

Financial Objective and Strategies

Our financial objective and strategies are intended to maintain our financial condition and facilitate corporate acquisitions to leverage our core portfolio of assets. Strategies are:

maintain debt to capitalization ratio of less than 40%; and

maintain debt to cash flow from operations of less than two times.

We believe that the execution of these strategies will attain our primary objectives. We will continue to act on acquisition opportunities that are strategic to our operations.

3.2 MAJOR PROJECTS

Upstream

Western Canada Enhanced Oil Recovery

During 2006, an alkaline surfactant polymer enhanced recovery project was implemented to extend the productive life of the Taber South Manville B Pool in Southern Alberta.

East Coast Canada Exploration and Delineation

In November 2006, we completed drilling of the North Amethyst K-15 delineation well in the Significant Discovery Licence ("SDL") 1044 southwest of White Rose. The results were encouraging and analysis is continuing on this reservoir. Our working interest in SDL 1044 is 72.5%.

In October 2006, we completed drilling of the West Bonne Bay F-12 delineation well and the F-12Z side track well in the SDL 1040 block, which is adjacent to the Terra Nova field. Preliminary results indicate hydrocarbons in the Upper Hibernia Reservoir. Further analysis will determine more about the resources in this reservoir. Our working interest in SDL 1040 is 27.78%.

In June 2006, we completed drilling of the White Rose O-28 delineation well and the O-28X side track well in the SDL 1024 adjacent to the western border of the White Rose South Avalon field. The results were encouraging and an additional delineation well to determine the areal extent of the reservoir is planned for 2007. Our working interest in SDL 1024 is 72.5%.

A 3-D seismic program was shot on Exploration Licence 1067, northwest of the White Rose oil field, covering 270 square kilometres and on Exploration Licence 1011 in the Fortune area, southwest of White Rose, covering 625 square kilometres. Our 2007 exploration and delineation drilling program currently includes three locations in the Jeanne d'Arc Basin.

At Terra Nova, we are currently participating in a delineation well in the Far East Block.

White Rose

In November 2006, a sixth production well was completed at the White Rose South Avalon field, which has increased productive capacity to 125 mbbls/day.

Tucker Oil Sands Project

At Tucker, the first five wells of the total 32 completed well pairs were producing at the end of December and steaming of the other wells continued. Tucker will continue to ramp up production through the next two years to achieve its design rate of 30 mbbls/day of bitumen.

Sunrise Oil Sands Project

The conceptual design for the upstream development at the Sunrise Oil Sands project was completed in late 2006. This aspect of the project includes options for field development, oil treatment and steam generation. Front-end engineering design for Sunrise has commenced and is scheduled to be complete by the third quarter of 2007.

Five water source wells were drilled and evaluated in the fourth quarter of 2006 and an additional five water source wells and 29 stratigraphic test wells are planned for the current winter drilling season. Additional seismic data will be acquired over the initial development area this winter to enhance the geological interpretation and enable better well placement. Collaboration with various industry participants continued on regional infrastructure issues, including an access highway and airport.

Caribou Lake and Saleski

During 2006, we participated in three land sales in the Saleski area and acquired leases totalling 84,320 acres. We now hold leases totalling 239,200 acres in the Saleski area. In December, we submitted an application to the Alberta Energy and Utilities Board and Alberta Environment for the first phase of the Caribou Lake project.

Conceptual development planning continued with water source and disposal well studies for both Saleski and Caribou Lake and determination of an appropriate bitumen recovery process for Saleski. At Caribou Lake, we completed the selection of 44 stratigraphic well locations to be drilled during the 2006/2007 winter drilling season.

Northwest Territories Exploration

A seismic program was completed during September 2006 that included our newly acquired Exploration Licence 441, which is contiguous with the eastern boundary of our Exploration Licence 397 containing the Stewart D-57 natural gas discovery. Based on the timing of this seismic program and subsequent analytical work we, with our partners, have decided to defer further exploration drilling until the winter of 2007/2008. This will allow for full incorporation of new seismic data into the prospect mapping that is currently underway.

China Exploration

During August 2006, we acquired three exploration blocks offshore China that in aggregate total 16,871 square kilometres. Block 29/06 is 9,265 square kilometres and located in the Pearl River Mouth Basin adjacent to Block 29/26, the location of the June 2006 Liwan natural gas discovery. Block 35/18 is 4,469 square kilometres and Block 50/14 is 3,137 square kilometres; both are located in the Yinggehai Basin west of Hainan Island. Under the terms of the agreement we will pay 100% of the costs to drill two wells on Block 29/06 and one well on each of the other two blocks. The China National Offshore Oil Corporation ("CNOOC") has the option to participate in up to 51% of any future development.

At the Liwan natural gas discovery a side track well confirmed the pay zones in the original well. We also completed shooting 400 square kilometres of 3-D seismic over the Liwan discovery and it is currently being analyzed in preparation for delineation drilling. We are currently seeking tenders to drill an exploration well on Block 04/35 in the East China Sea and expect a spud date in the first half of 2007.

In the fourth quarter of 2006, the CNOOC agreed to a 3-D seismic program on Block 29/26, on which the Liwan natural gas discovery is located and also on the adjacent Block 29/06. The program will investigate several structures with characteristics similar to those of Liwan.

A deep water rig has been secured for a three-year term commencing in mid-2008 and will initially be deployed in the South China Sea.

Indonesia Natural Gas Development

At Madura, negotiations for a natural gas sales agreement are continuing. Development of the BD natural gas field is contingent on receiving government approval. In September 2006, Husky signed the Production Sharing Contract for the 4,254 square kilometre East Bawean II Block and is currently planning to commence a 3-D seismic program in the second half of 2007.

Midstream

Lloydminster Upgrader

The front-end engineering design for the major expansion of the Lloydminster Upgrader to 150 mbbls/day is approximately 25% complete. Completion of this engineering design is scheduled for the end of 2007.

Lloydminster Pipeline

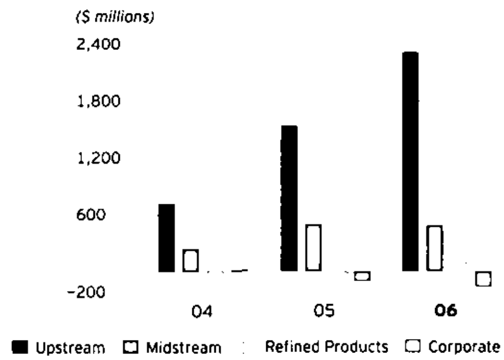
The Lloydminster to Hardisty, Alberta pipeline expansion project phase one is currently underway and is nearing completion. Phase two is expected to be completed by September 2007. The additional 24-inch pipeline will facilitate movement of heavy crude oil. Ultimately, this project will also facilitate movement of a higher volume of synthetic crude oil from our upgrader.

Refined Products

Lloydminster and Minnedosa Ethanol Plants

To meet the increasing demand for ethanol blended gasoline, we commenced construction of two motor fuel grade ethanol plants. One plant is located adjacent to our Upgrader at Lloydminster, Saskatchewan and was commissioned in September 2006. The other is at Minnedosa, Manitoba, the site of our existing ethanol plant. Construction of the new plant at Minnedosa is expected to be completed during the third quarter of 2007 and planned to be fully operational in the fourth quarter of 2007. Each plant is designed to have throughput capacity of 130 million litres of ethanol per year.

Segmented Earnings



4.0 Results of Operations

Earnings from our three business segments increased each year from 2004 to 2006 and in each year our upstream business provided the majority of earnings. Midstream earnings were driven primarily by the upgrading operations, which reflect the wide differential between heavy and light crude oil.

4.1 UPSTREAM

2006 Earnings $2,295 Million, Up $771 Million from 2005

Earnings Summary and 2006 Variance Analysis

Upstream earnings were $771 million higher in 2006 than in 2005 due to:

- higher sales volume of light crude oil from White Rose;
- higher crude oil prices; and
- lower natural gas royalties.

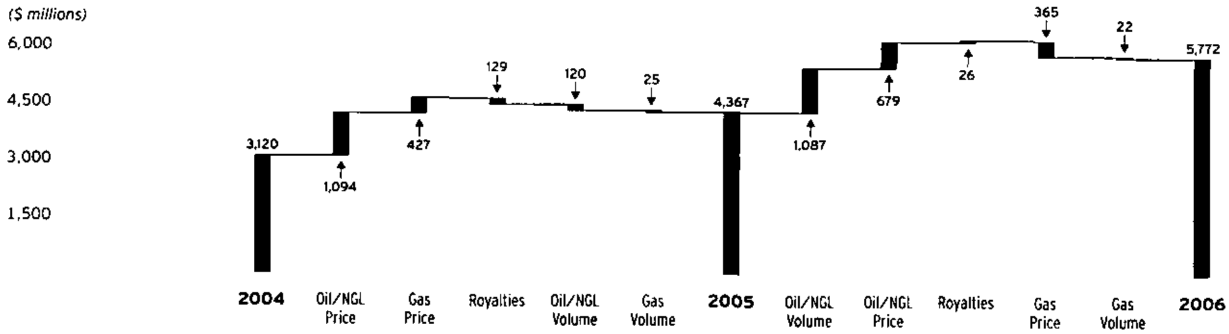
Partially offset by:

- lower natural gas prices and sales volume;
- lower sales volume of light crude oil from Terra Nova and Wenchang;
- higher operating costs;
- higher depletion, depreciation and amortization; and
- higher income taxes.

Upstream Earnings Summary

($ millions)	**2006**	2005	2004
Gross revenues	**$ 6,586**	$ 5,207	$ 4,392
Royalties	**814**	840	711
Hedging loss	**–**	–	561
Net revenues	**5,772**	4,367	3,120
Operating and administration expenses	**1,321**	1,050	967
Depletion, depreciation and amortization	**1,476**	1,144	1,077
Income taxes	**680**	649	363
Earnings	**$ 2,295**	$ 1,524	$ 713

Net Revenue Variance Analysis



Operating Costs

Total upstream operating costs averaged $8.77/boe in 2006 compared with $8.12/boe in 2005.

Operating costs in Western Canada averaged $9.79/boe in 2006 compared with $8.59/boe in 2005. Increasing operating costs in Western Canada are related to the nature of exploitation necessary to manage production from maturing fields and new, more extensive, but less prolific, reservoirs. Western Canada operations require increasing amounts of infrastructure including equipping of more wells, more extensive pipeline systems and crude trucking and increased costs associated with operating larger and more extensive natural gas compression systems. These factors in turn require higher energy consumption, workovers and generally more material costs. In addition, higher levels of industry activity lead naturally to competition for resources and consequential higher service rates and unit costs.

Operating costs at the East Coast offshore operations averaged $5.48/bbl in 2006 compared with $5.14/bbl in 2005. Unit operating costs increased as a result of maintenance costs combined with low production volume at Terra Nova, partially offset by lower unit operating costs at White Rose, which benefited by higher production and reliable asset performance. Unit operating costs at White Rose averaged $4.22/bbl in 2006.

Operating costs at the South China Sea offshore operations averaged $3.61/bbl compared with $2.92/bbl in 2005. Increased unit operating costs are due to natural production declines.

Depletion, Depreciation and Amortization ("DD&A")

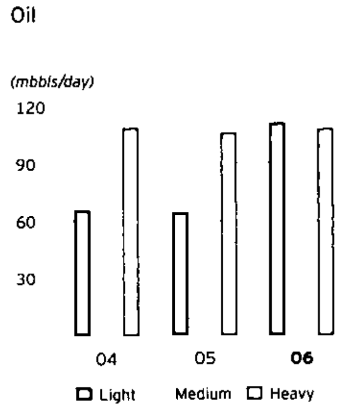
DD&A under the full cost method of accounting for oil and gas activities is calculated on a country-by-country basis. The DD&A rate is calculated by dividing the capital costs subject to DD&A by the proved oil and gas reserves expressed as equivalent barrels or boe. The resultant dollar per boe is assigned to each boe of production to determine the DD&A expense for the period.

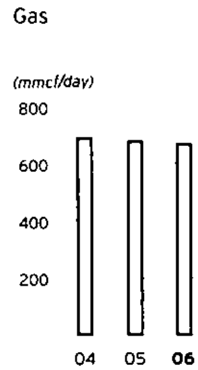
Total DD&A averaged $11.24/boe in 2006 compared with $9.95/boe in 2005.

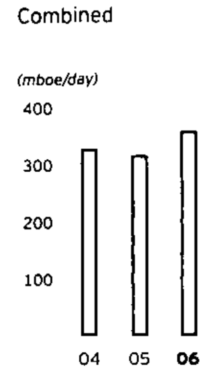
DD&A in Canada averaged $11.24/boe in 2006 compared with $10.10/boe in 2005. The increase in DD&A is mainly due to higher capital. Increasing capital is due to increased drilling and associated infrastructure in Western Canada and large capital investment required to develop offshore reserves off the East Coast of Canada.

DD&A in China averaged $11.22/boe in 2006 compared with $7.23/boe in 2005. Increasing unit DD&A results from lower reserves due to reservoir depletion.

Production







Daily Production, before Royalties

		2006	2005	2004
Light crude oil & NGL	*(mbbls/day)*	**111.0**	64.6	66.2
Medium crude oil	*(mbbls/day)*	**28.5**	31.1	35.0
Heavy crude oil & bitumen	*(mbbls/day)*	**108.1**	106.0	108.9
Total crude oil & NGL	*(mbbls/day)*	**247.6**	201.7	210.1
Natural gas	*(mmcf/day)*	**672.3**	680.0	689.2
Barrels of oil equivalent (6:1)	*(mboe/day)*	**359.7**	315.0	325.0

Average Sales Prices

		2006	2005	2004
Crude oil	*($/bbl)*			
Light crude oil & NGL		**$ 69.06**	$ 61.56	$ 48.34
Medium crude oil		**49.48**	43.44	36.13
Heavy crude oil		**39.92**	31.09	28.66
Total average		**54.08**	42.75	36.07
Total average after hedging		**54.08**	42.75	28.43
Natural gas	*($/mcf)*			
Average		**$ 6.47**	$ 7.96	$ 6.25
Average after hedging		**6.47**	7.96	6.24

Upstream Revenue Mix [1]

	2006	2005	2004
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	**45**	29	27
Medium crude oil	**7**	9	11
Heavy crude oil & bitumen	**24**	24	27
Natural gas	**24**	38	35
Total	**100**	100	100

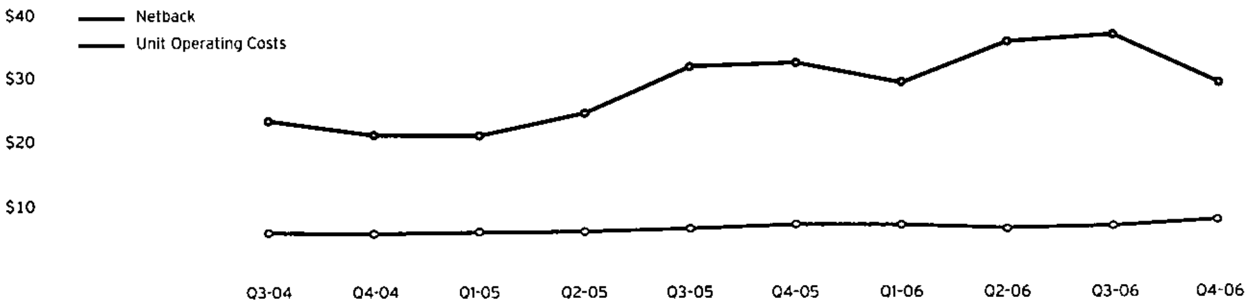
Effective Royalty Rates [1]

	2006	2005	2004
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	**8**	14	13
Medium crude oil	**18**	18	18
Heavy crude oil	**13**	12	12
Bitumen	**1**	–	–
Natural gas	**18**	20	22
Total	**13**	16	16

(1) Before commodity hedging.

Netback and Unit Operating Costs

($/boe)



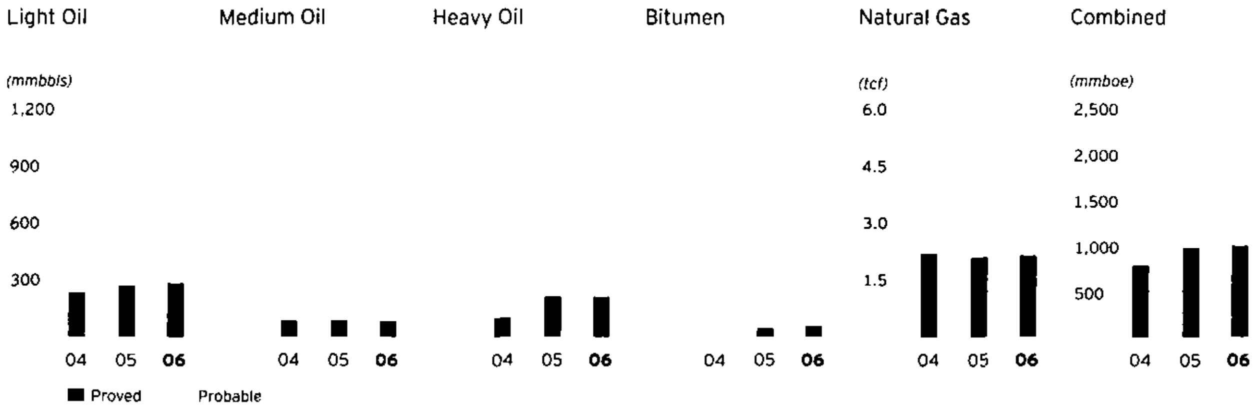
Operating Netbacks

	Western Canada			East Coast			International			Total		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Light Crude Oil *($ per boe)* (1)												
Sales price	**59.89**	60.74	46.12	**71.18**	62.61	47.87	**73.60**	63.15	47.66	**68.51**	61.86	46.95
Royalties	**7.34**	8.66	7.76	**1.95**	5.91	1.80	**12.17**	5.93	4.91	**4.49**	7.22	5.71
Operating costs	**11.89**	9.86	8.94	**5.48**	5.14	3.28	**3.81**	2.92	2.16	**6.96**	6.88	5.82
	40.66	42.22	29.42	**63.75**	51.56	42.79	**57.62**	54.30	40.59	**57.06**	47.76	35.42
Medium Crude Oil *($ per boe)* (1)												
Sales price	**48.97**	43.67	36.20	**-**	-	-	**-**	-	-	**48.97**	43.67	36.20
Royalties	**8.61**	7.77	6.10	**-**	-	-	**-**	-	-	**8.61**	7.77	6.10
Operating costs	**13.09**	10.97	10.07	**-**	-	-	**-**	-	-	**13.09**	10.97	10.07
	27.27	24.93	20.03	**-**	-	-	**-**	-	-	**27.27**	24.93	20.03
Heavy Crude Oil *($ per boe)* (1)												
Sales price	**39.91**	31.22	28.73	**-**	-	-	**-**	-	-	**39.91**	31.22	28.73
Royalties	**5.16**	3.75	3.38	**-**	-	-	**-**	-	-	**5.16**	3.75	3.38
Operating costs	**11.10**	9.90	9.33	**-**	-	-	**-**	-	-	**11.10**	9.90	9.33
	23.65	17.57	16.02	**-**	-	-	**-**	-	-	**23.65**	17.57	16.02
Total Crude Oil *($ per boe)* (1)												
Sales price	**44.90**	38.91	33.48	**71.18**	62.61	47.87	**73.60**	63.15	47.66	**53.55**	42.83	35.72
Royalties	**6.14**	5.41	4.75	**1.95**	5.91	1.80	**12.17**	5.93	4.91	**5.28**	5.49	4.58
Operating costs	**11.60**	10.10	9.41	**5.48**	5.14	3.28	**3.81**	2.92	2.16	**9.53**	9.13	8.36
	27.16	23.40	19.32	**63.75**	51.56	42.79	**57.62**	54.30	40.59	**38.74**	28.21	22.78
Natural Gas *($ per mcfge)* (2)												
Sales price	**6.65**	8.02	6.25	**-**	-	-	**-**	-	-	**6.65**	8.02	6.25
Royalties	**1.37**	1.76	1.44	**-**	-	-	**-**	-	-	**1.37**	1.76	1.44
Operating costs	**1.18**	1.04	0.89	**-**	-	-	**-**	-	-	**1.18**	1.04	0.89
	4.10	5.22	3.92	**-**	-	-	**-**	-	-	**4.10**	5.22	3.92
Equivalent Unit *($ per boe)* (1)												
Sales price	**42.91**	42.53	35.01	**71.18**	62.61	47.87	**73.60**	63.15	47.66	**49.34**	44.69	36.34
Royalties	**6.97**	7.45	6.22	**1.95**	5.91	1.80	**12.17**	5.93	4.91	**6.19**	7.29	5.96
Operating costs	**9.79**	8.59	7.85	**5.48**	5.14	3.28	**3.81**	2.92	2.16	**8.77**	8.12	7.32
	26.15	26.49	20.94	**63.75**	51.56	42.79	**57.62**	54.30	40.59	**34.38**	29.28	23.06

(1) Includes associated co-products converted to boe.

(2) Includes associated co-products converted to mcfge.

Oil and Gas Reserves



Oil and Gas Reserves

Husky applied for and was granted an exemption from Canada's National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and provides oil and gas reserves disclosures in accordance with the United States Securities and Exchange Commission ("SEC") guidelines and the United States Financial Accounting Standards Board ("FASB") disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101.

For more detail on our oil and gas reserves and the disclosures with respect to the FASB's Statement No. 69, "Disclosures about Oil and Gas Producing Activities" and the differences between our disclosures and those prescribed by National Instrument 51-101, refer to our Annual Information Form available at www.sedar.com or our Form 40-F available at www.sec.gov or on our website at www.huskyenergy.ca.

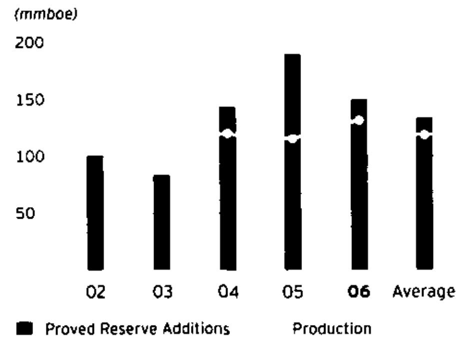
McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Crude Oil and Natural Gas Reserves Summary [(1)]

(constant prices and costs before royalties)	Proved Developed			Proved Undeveloped			Total Proved			Proved and Probable		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Crude oil *(mmbbls)*												
Light & NGL	**257**	226	191	**30**	47	47	**287**	273	238	**428**	462	465
Medium	**79**	80	80	**8**	11	6	**87**	91	86	**102**	105	96
Heavy	**135**	140	91	**78**	77	14	**213**	217	105	**289**	291	150
Bitumen	**47**	–	–	**13**	48	–	**60**	48	–	**1,187**	951	79
	518	446	362	**129**	183	67	**647**	629	429	**2,006**	1,809	790
Natural gas *(bcf)*	**1,703**	1,710	1,745	**440**	426	424	**2,143**	2,136	2,169	**2,626**	2,709	2,724
Total *(mmboe)*	**802**	731	653	**202**	254	138	**1,004**	985	791	**2,444**	2,260	1,244

(1) Refer to Section 13 for Oil and Gas Reserves definitions.

Reserves Replacement



2006 Reserve Additions

Our proved oil and gas reserves are estimated in accordance with the regulations and guidance of the SEC and the FASB which, among other things, require proved reserves to be evaluated using prices in effect on the date of the reserve report.

Additions of Crude Oil and NGL

The additions to crude oil and NGL proved reserves in 2006 amounted to 108 mmbbls and were largely from the White Rose oil field, heavy oil properties located in the Lloydminster area and the Tucker Oil Sands project. The change in proved reserves from net acquisition/divestiture activity was minor in 2006, resulting in additions of approximately one mmbbls of crude oil and NGL.

At the White Rose oil field, offshore Newfoundland and Labrador, proved reserve additions resulted from a combination of technical revisions and improved recovery based on the better than expected performance of the reservoir and the pressure maintenance scheme being utilized. Additions of proved reserves of light crude oil totalled 41 mmbbls at White Rose. White Rose produced 23 mmbbls in 2006.

At the Tucker Oil Sands project, located in the Cold Lake Oil Sands Deposits, proved reserve additions amounted to 13 mmbbls of bitumen bringing the total proved reserves at Tucker to 60 mmbbls at December 31, 2006. These proved reserves are attributable to the first phase of the Tucker SAGD project, which comprises 1.5 sections or approximately 3.9 square kilometres, and are expected to be recovered by 40 well pairs, of which 32 are complete. An additional 100 well pairs are currently contemplated to complete development at Tucker.

Additions of Natural Gas

The additions to natural gas proved reserves from discoveries, extensions and improved recovery amounted to 317 bcf and acquisitions of 25 bcf, which were partially offset by net technical revisions of negative 87 bcf and divestitures of three bcf. The additions from discoveries, extensions and improved recovery were primarily from natural gas properties throughout the Western Canada Sedimentary Basin; approximately 38% of this class of change was attributable to four properties and 44% of the additions were located in the foothills/deep basin region of the basin. Approximately 22% of the net negative revision of proved natural gas was due to low natural gas prices at December 31, 2006, a change that is expected to reverse when natural gas prices recover. The remaining negative revisions were due, for the most part, to more rapid production decline rates than expected.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					East Coast					
(constant prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves at											
December 31, 2005	167	91	217	48	2,136	89	17	-	629	2,136	985
Technical revisions	(3)	(1)	(2)	(1)	(87)	31	2	-	26	(87)	11
Purchase of reserves in place	1	1	-	-	25	-	-	-	2	25	6
Sale of reserves in place	(1)	-	-	-	(3)	-	-	-	(1)	(3)	(1)
Discoveries, extensions and improved recovery	13	6	37	13	317	12	-	-	81	317	134
Production	(11)	(10)	(39)	-	(245)	(25)	(5)	-	(90)	(245)	(131)
Proved reserves at December 31, 2006	**166**	**87**	**213**	**60**	**2,143**	**107**	**14**	**-**	**647**	**2,143**	**1,004**
Proved and probable reserves											
At December 31, 2006	**219**	**102**	**289**	**1,187**	**2,533**	**186**	**23**	**93**	**2,006**	**2,626**	**2,444**
At December 31, 2005	225	105	291	951	2,542	207	30	167	1,809	2,709	2,260

Reconciliation of Proved Developed Reserves

	Canada						Intn'l	Total		
	Western Canada					East Coast				
(constant prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves at										
December 31, 2005	151	80	140	-	1,710	59	16	446	1,710	731
Revision of previous estimate	2	6	17	47	63	58	2	132	63	142
Purchase of reserves in place	1	1	-	-	14	-	-	2	14	4
Sale of reserves in place	(1)	-	-	-	(3)	-	-	(1)	(3)	(1)
Improved recovery	5	2	17	-	164	5	-	29	164	57
Production	(11)	(10)	(39)	-	(245)	(25)	(5)	(90)	(245)	(131)
Proved developed reserves at December 31, 2006	**147**	**79**	**135**	**47**	**1,703**	**97**	**13**	**518**	**1,703**	**802**

Upstream Capital Expenditures

Capital Expenditures (1)

($ millions)	**2006**	2005	2004
Exploration			
Western Canada	**$ 497**	$ 389	$ 322
East Coast Canada and Frontier	**79**	66	24
International	**77**	55	18
	653	510	364
Development			
Western Canada	**1,675**	1,618	1,211
East Coast Canada	**279**	579	515
International	**20**	23	67
	1,974	2,220	1,793
	$ 2,627	$ 2,730	$ 2,157

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Western Canada Drilling

		2006		2005		2004	
(wells)		**Gross**	**Net**	Gross	Net	Gross	Net
Exploration	Oil	**101**	**99**	89	85	45	39
	Gas	**330**	**192**	392	196	234	180
	Dry	**26**	**24**	36	36	34	33
		457	**315**	517	317	313	252
Development	Oil	**590**	**543**	466	433	552	499
	Gas	**565**	**490**	610	551	807	740
	Dry	**25**	**22**	42	39	57	53
		1,180	**1,055**	1,118	1,023	1,416	1,292
Total		**1,637**	**1,370**	1,635	1,340	1,729	1,544

Canada

In 2006, upstream capital spending in Canada amounted to $2,530 million, down from $2,652 million in 2005. Capital spending in 2006 comprised $1,443 million on Western Canada conventional areas, $453 million in the Lloydminster heavy oil region, $276 million in the Alberta oil sands regions, $313 million for East Coast development and $45 million for East Coast and Northwest Territories exploration.

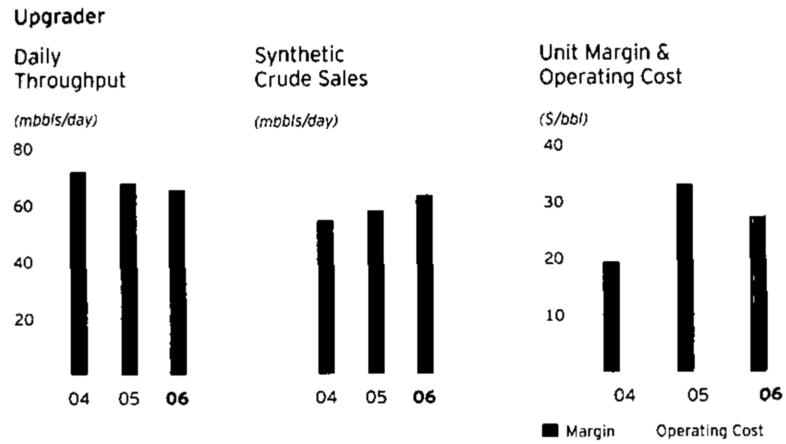
In 2006, spending on exploration activities comprised $236 million in the foothills and deep basin regions, $81 million in the Lloydminster heavy oil region, $98 million in the Alberta oil sands regions and $82 million in the remainder of the conventional Western Canada Sedimentary Basin.

In the Lloydminster heavy oil production region, capital spending amounted to $453 million in 2006, $81 million of which was classified as exploration. Spending in this area is focused mainly on SAGD, cyclic steam and cold production techniques that are utilized to produce the 10 to 14 degree API heavy crude oil. Production of heavy crude oil is more capital intensive due to the extensive infrastructure and also for facilities required for thermal recovery techniques.

Exploration spending in the foothills and deep portion of the greater Western Canada Sedimentary Basin amounted to $236 million in 2006, up from $213 million in 2005. Exploration in this region, which extends along the eastern slopes of the Rocky Mountains in Alberta and into northeastern British Columbia, involves drilling deep wells into high pressure natural gas formations.

Spending on oil sands projects amounted to $276 million in 2006, down from $366 million in 2005. Our Tucker SAGD oil sands project was commissioned during October 2006 and operations for the remainder of the year were largely concentrated on steaming the formation. We spent $178 million on the Tucker project in 2006. At the Sunrise Oil Sands project, the front-end engineering design commenced. During 2006, we spent $43 million on Sunrise and $55 million on other oil sands prospects.

At White Rose, production continued to ramp up through 2006 with the drilling of two additional production wells in the year.



During 2006, exploration activities offshore the East Coast involved three delineation wells, one on Significant Discovery Licence 1024 to the north west of White Rose, one at West Bonne Bay on Significant Discovery Licence 1040 and one at North Amethyst on Significant Discovery Licence 1044 to the south west of White Rose. In 2006, capital spending for exploration and development activities in this region amounted to $358 million, down from $645 million in 2005.

International

Exploration spending in China involved the drilling of an exploration well and a side track well at Liwan in the South China Sea. The well encountered a large natural gas reservoir and the results are being evaluated. Approximately 400 square kilometres of 3-D seismic was shot during 2006 on the Liwan discovery area.

In Indonesia, front-end engineering design for the Madura Strait natural gas and NGL project is underway. However, field development is contingent on the negotiation of a natural gas sales contract, which is ongoing.

Total capital spending on international activities amounted to $97 million.

4.2 MIDSTREAM

2006 Earnings $482 Million, Down $13 Million from 2005

The midstream business is dominated by upgrading operations, which is a margin business that adds value to heavy crude oil through its conversion to synthetic light crude oil.

Upgrading earnings in 2006 were $28 million less than 2005 due to narrower differentials and increased electrical energy costs offset by higher sales volume of synthetic crude, lower costs for natural gas and thermal energy and lower income taxes.

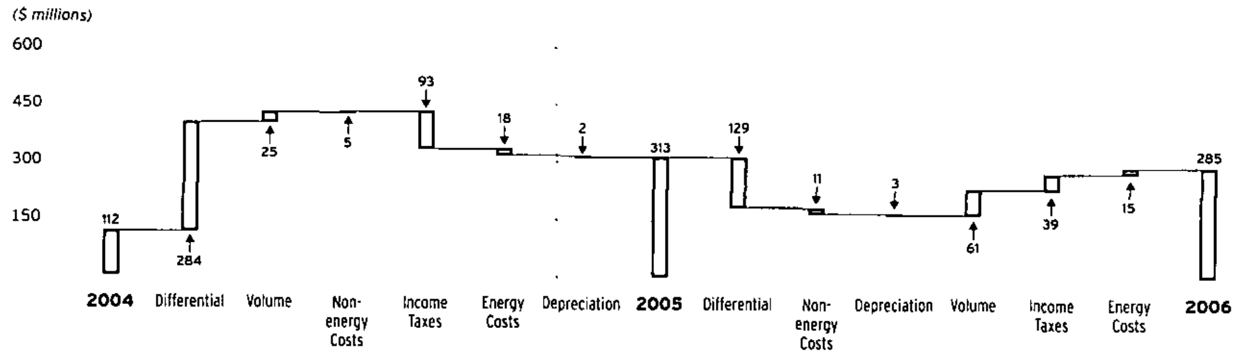
Upgrading Earnings Summary and 2006 Variance Analysis

Upgrading Earnings Summary

($ millions, except where indicated)		**2006**	2005	2004
Gross margin		**$ 624**	$ 692	$ 383
Operating costs		**224**	228	214
Other recoveries		**(6)**	(6)	(5)
Depreciation and amortization		**24**	21	19
Income taxes		**97**	136	43
Earnings		**$ 285**	$ 313	$ 112
Upgrader throughput (1)	*(mbbls/day)*	**71.0**	66.6	64.6
Synthetic crude oil sales	*(mbbls/day)*	**62.5**	57.5	53.7
Upgrading differential	*($/bbl)*	**$ 26.16**	$ 30.70	$ 17.79
Unit margin	*($/bbl)*	**$ 27.35**	$ 33.01	$ 19.48
Unit operating cost (2)	*($/bbl)*	**$ 8.65**	$ 9.38	$ 9.07

(1) Throughput includes diluent returned to the field.
(2) Based on throughput.

Upgrading Earnings Variance Analysis



Upgrading Differential

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related upgrading costs. An increase in the price of blended heavy crude oil feedstock that is not accompanied by an equivalent increase in the sales price of synthetic crude oil would reduce the profitability of our upgrading operations. We have significant crude oil production volumes that trade at a discount to light crude oil, and any negative effect of a narrower differential on upgrading operations, caused by higher heavy crude pricing, would be more than offset by a positive effect on revenues in the upstream segment from heavy oil production.

Infrastructure and Marketing Earnings Summary and 2006 Variance Analysis

Infrastructure and marketing earnings in 2006 increased by $15 million compared with 2005 due to higher crude oil pipeline margins, higher natural gas marketing earnings, higher cogeneration earnings and lower income taxes, partially offset by lower earnings from blended heavy crude oil marketing.

Infrastructure and Marketing Earnings Summary

($ millions, except where indicated)		**2006**	2005	2004
Gross margin				
Pipeline		**$ 104**	$ 92	$ 84
Other infrastructure and marketing		**208**	217	136
		312	309	220
Other expenses		**11**	10	8
Depreciation and amortization		**24**	21	21
Income taxes		**80**	96	63
Earnings		**$ 197**	$ 182	$ 128
Aggregate pipeline throughput	*(mbbls/day)*	**475**	474	492

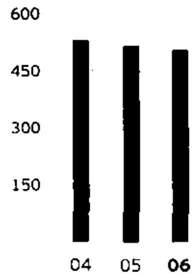
Midstream Capital Expenditures

Midstream capital expenditures of $252 million in 2006 were largely for upgrader expansion front-end engineering design, debottlenecking and reliability projects and pipeline upgrades and expansion compared with $157 million in 2005.

Light Oil Product Marketing

Volume

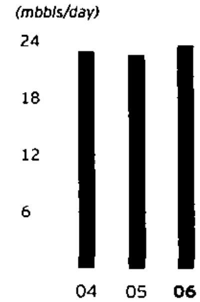
Outlets



Volume per Outlet

Asphalt Products

Volume



4.3 REFINED PRODUCTS

2006 Earnings $106 Million, Up $24 Million from 2005

The refined products business includes the light oil product marketing business that distributes motor fuel and other consumer products through retail and wholesale outlets and the asphalt products marketing business that distributes asphalt related construction products to industrial customers. The light oil products business relies primarily on acquiring refined product from other refiners either directly or through custom processing agreements and from our own regional refinery located at Prince George, British Columbia. Our supply of asphalt product comes from our asphalt plant in Lloydminster, Alberta. Both are margin businesses.

Refined Products earnings in 2006 increased by $24 million compared with 2005 due to:

- higher margins for gasoline and distillates;
- higher ancillary income;
- higher sales volume of asphalt products;
- lower administrative costs; and
- lower income taxes.

Partially offset by:

- higher depreciation; and
- lower sales volume of gasoline and distillates.

Refined Products Earnings Summary

($ millions, except where indicated)		**2006**	2005	2004
Gross margin				
Fuel sales		**$ 138**	$ 126	$ 93
Ancillary sales		**36**	34	30
Asphalt sales		**94**	91	51
		268	251	174
Operating and other expenses		**74**	75	71
Depreciation and amortization		**48**	47	38
Income taxes		**40**	47	24
Earnings		**$ 106**	$ 82	$ 41
Number of fuel outlets		**505**	515	531
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.7**	8.9	8.4
Light oil products per outlet	*(thousand litres/day)*	**12.9**	12.7	11.7
Asphalt products	*(mbbls/day)*	**23.4**	22.5	22.8
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**9.0**	9.7	9.8
Lloydminster refinery	*(mbbls/day)*	**27.1**	25.5	25.3
Ethanol production	*(thousand litres/day)*	**59.7**	25.6	26.0

Refined Products Margins

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which in turn increase or decrease the cost of refinery feedstock and the cost of refined product purchased from third-party refiners. Our ability to maintain refined products margins in an environment of higher feedstock costs is contingent on whether the market will permit us to pass on higher costs to our customers.

Refined Products Capital Expenditures

Refined Products capital expenditures in 2006 of $285 million were primarily for marketing outlet construction and upgrades, the Prince George refinery upgrade and construction of the Lloydminster and Minnedosa ethanol plants compared with $191 million in 2005.

Integration

Husky's production of light, medium and heavy crude oil and natural gas and the efficient operation of our upgrader, refineries and other infrastructure provide opportunities to take advantage of any fluctuation in commodity prices while assisting in managing commodity price volatility. Although we are predominantly an oil and gas producer, the nature of our integrated operations is such that the upstream business segment's output provides input to the midstream and refined products segments.

4.4 CORPORATE

2006 Expense $157 Million, Up $59 Million from 2005

Corporate expense increased by $59 million in 2006 compared with 2005 largely due to:

- lower capitalized interest consistent with the commissioning of major projects;
- 2005 expenses offset by proceeds of a one-time litigation settlement, similar proceeds absent in 2006; and
- increased administration expenses consistent with higher staff levels.

Partially offset by:

- lower intersegment profit eliminations;
- lower stock-based compensation; and
- lower debt costs.

Corporate Earnings Summary

($ millions) income (expense)	**2006**	2005	2004
Intersegment eliminations – net	**$ 20**	$ (50)	$ (14)
Administration expenses	**(35)**	(19)	(27)
Stock-based compensation	**(138)**	(171)	(67)
Accretion	**(3)**	(2)	(2)
Other – net	**(23)**	49	(8)
Depreciation and amortization	**(27)**	(23)	(24)
Interest on debt	**(125)**	(146)	(135)
Interest capitalized	**33**	114	75
Foreign exchange	**24**	31	120
Income taxes	**117**	119	94
Earnings (loss)	**$ (157)**	$ (98)	$ 12

Foreign Exchange Summary

($ millions)	2006	2005	2004
(Gain) loss on translation of U.S. dollar denominated long-term debt			
Realized	**$ (42)**	$ (13)	$ (10)
Unrealized	**35**	(38)	(140)
	(7)	(51)	(150)
Cross currency swaps			
Realized	**47**	-	-
Unrealized	**(43)**	14	27
	4	14	27
Other (gains) losses	**(21)**	6	3
	$ (24)	$ (31)	$ (120)
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.858**	U.S. $0.831	U.S. $0.774
At end of year	**U.S. $0.858**	U.S. $0.858	U.S. $0.831

Foreign Exchange Risk

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of our expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will effectively decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will effectively increase the revenues received from the sale of oil and gas commodities.

In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2006, 81% or $1.3 billion of our long-term debt was denominated in U.S. dollars. The Cdn/U.S. exchange rate at the end of 2006 was $1.1653. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 55% when cross currency swaps are included. Refer to Section 6.6, "Financial Risk and Risk Management."

Corporate Capital Expenditures

Corporate capital expenditures of $37 million in 2006 were mostly for computer hardware, software, office furniture and equipment and compared with $21 million in 2005.

Consolidated Income Taxes

Consolidated income taxes decreased in 2006 to $780 million from $809 million in 2005 largely as a result of Federal, Alberta and Saskatchewan statutory tax rate reductions enacted in 2006.

In 2006, a recovery of future taxes resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million).

In 2006, current income taxes totalled $678 million and comprised $632 million of Canadian income tax, $64 million in respect of the Wenchang oil field operation and a net capital tax recovery of $18 million.

The following table shows the effect of non-recurring tax benefits for the periods noted:

($ millions)	2006	2005	2004
Income taxes before tax amendments	**$ 1,108**	$ 813	$ 439
Canadian federal and provincial tax amendments	**328**	4	40
Income taxes as reported	**$ 780**	$ 809	$ 399

Husky's Canadian Tax Pools

($ millions)	2006	2005	2004
Canadian exploration expense	**$ 117**	$ 78	$ -
Canadian development expense	**2,136**	2,033	1,616
Canadian oil and gas property expense	**666**	721	557
Foreign exploration and development expense	**252**	240	212
Undepreciated capital costs	**4,644**	4,249	3,269
Other	**21**	27	22
	$ 7,836	$ 7,348	$ 5,676

4.5 2005 COMPARED WITH 2004

The following is an abbreviated analysis of the major variance in our 2005 results of operations compared with 2004.

Net earnings in 2005 were $2,003 million compared with $1,006 million in 2004. The increase of $997 million was attributable to the following:

Upstream – increase of $811 million

higher crude oil and natural gas prices; and
absence of commodity price hedging loss in 2005.

Partially offset by:

lower sales volume of crude oil and natural gas;
higher operating costs and DD&A;
higher royalties; and
higher income taxes.

Midstream – increase of $255 million

wider upgrading differential;
higher sales volume of synthetic crude oil;
higher income from oil and gas commodity marketing;
higher heavy crude oil tariffs;
higher Lloyd blend marketing margins;
higher crude oil and NGL trading; and
higher cogeneration income.

Partially offset by:

lower heavy crude oil pipeline throughput;
higher energy and non-energy related unit operating costs; and
higher income taxes.

Refined Products – increase of $41 million

higher marketing margins and sales volume for gasoline and distillates;
higher marketing margins of asphalt products; and
higher restaurant and convenience store income.

Partially offset by:

slightly lower sales volume of asphalt products;
higher depreciation and amortization; and
higher income taxes.

Corporate – expense increased by $110 million

higher intersegment profit eliminated;
higher stock-based compensation;
higher interest costs;
lower foreign exchange gains on translation of U.S. dollar denominated debt; and
provision for retrospective insurance premiums in respect of past claims on a mutual insurance consortium.

Partially offset by:

proceeds from a litigation settlement; and
higher capitalized interest resulting from a higher capital base for the White Rose and Tucker projects.

5.0 2007 Outlook

5.1 GENERAL ECONOMY

The expectations for the global economy in 2007 are for slightly slower growth. Crude oil price forecasters have decreased their predictions as actual current crude oil prices have fallen. History has taught us that crude oil prices are and will likely remain volatile.

5.2 2007 CAPITAL PROGRAM

Husky plans to invest capital in the following segments in 2007:

($ millions)	2007 Estimate [1]
Upstream	
Western Canada – oil & gas	$ 1,840
– oil sands	330
East Coast Canada	290
International	160
	2,620
Midstream	380
Refined Products	140
Corporate	40
	$ 3,180

(1) Excludes capitalized administrative costs and capitalized interest.

5.3 UPSTREAM

Production Outlook

		2007	2006 Actual
Light crude oil & NGL	*(mbbls/day)*	128–135	111
Medium crude oil	*(mbbls/day)*	28–30	29
Heavy crude oil & bitumen	*(mbbls/day)*	122–130	108
Total crude oil & NGL	*(mbbls/day)*	278–295	248
Natural gas	*(mmcf/day)*	670–690	672
Barrels of oil equivalent (6:1)	*(mboe/day)*	390–410	360

Western Canada Conventional

Although the ability to easily identify and produce conventional reserves is diminished for the Western Canada Sedimentary Basin, the basin still contains a vast quantity of undiscovered reserves. These are smaller accumulations dispersed throughout the undisturbed plains and accumulations in the deep basin and overthrust belt along the eastern slopes of the Rocky Mountains that are challenging to access. Exploitation of these areas will require careful attention to a number of variables including new geological tools, emerging enhanced recovery techniques and optimization of economics through maximal utilization of existing infrastructure. We will continue to exploit these conventional reserves and, at the same time, explore for and develop the large and prolific basins off the East Coast of Canada, in the offshore basins of China and Indonesia and the oil sands regions of Alberta. In addition, we will augment our natural gas production with unconventional production such as coal bed methane and tight reservoirs. We expect our conventional oil equivalent production, including primary heavy crude production, from the Western Canada Sedimentary Basin to account for approximately 64% of our production in 2007, down from 72% in 2006.

We expect to replace a large portion of our conventional production in Western Canada from development of our current oil sands projects, further exploitation in the Jeanne d'Arc basin off the East Coast of Canada and from further exploitation of Wenchang in China and development of the Madura natural gas field in Indonesia.

Capital expenditures for development and exploration on our conventional Western Canada properties are expected to account for approximately 64% of the total $2.6 billion in upstream capital expenditures in 2007, down from 70% in 2006. In 2007, capital expenditures will increase for heavy oil development, particularly for our projects utilizing thermal recovery techniques and for oil sands development.

Oil Sands

Our current schedule for oil sands development is outlined below:

- complete a downstream solution that addresses infrastructure, upgrading and refining;
- ramp up production at Tucker to an average of 12 to 18 mbbls/day of bitumen during 2007;
- complete Sunrise front-end engineering design and sanction by the fourth quarter of 2007;
- commence preliminary design and evaluation of a small project in the Caribou Lake oil sands area; and
- commence submission of a pilot project to test various recovery techniques over the next few years in the Saleski oil sands area.

We view the full scale commercial development of Caribou Lake to be a medium-term project and Sunrise and Saleski to be long-term projects.

Canada – East Coast and Northwest Territories

On the East Coast, we will continue with the development and delineation of the White Rose field, including evaluating the economics and technical feasibility of natural gas developments off the East Coast, including the natural gas resources in the northern section of the White Rose field. In addition, we will continue to identify and evaluate new prospects off the East Coast with an emphasis on the Jeanne d'Arc Basin.

In the Jeanne d'Arc Basin, effective January 15, 2007, we acquired 100% working interest in an Exploration Licence totalling 61,375 acres and 50% working interest in two Exploration Licences totalling 127,457 acres.

In 2007 in the Northwest Territories, we will proceed with delineation and evaluation of the Summit Creek B-44 discovery that confirmed several productive intervals within a 180-metre zone. We and our partners hold over one million acres covering the central extent of this play.

China and Indonesia

In China, we will continue to pursue offshore prospects and the development of the Liwan natural gas discovery.

In Indonesia, we have been involved in protracted negotiations to establish a natural gas sales contract and an extension to the production sharing agreement and we expect to conclude these arrangements in 2007. We estimate that development construction will take approximately three years following project sanction. In addition, we will commence an exploration program on the East Bawean II block acquired in 2006.

5.4 MIDSTREAM

In 2007, we will maintain and optimize infrastructure to capitalize on increasing activity in the bitumen corridor, which extends from Lloydminster north to Fort McMurray, Alberta. We will also pursue expansion of ancillary businesses including transportation, storage, cogeneration and upgrading. We will complete the second phase of the pipeline expansion between Lloydminster and Hardisty, Alberta by September 2007. We expect to complete the front-end engineering design for an expansion of the Lloydminster Heavy Oil Upgrader to a capacity of 150 mbbls/day by the end of 2007 followed by project sanction subject to satisfactory economics.

5.5 REFINED PRODUCTS

In 2007, we plan to complete construction of the second ethanol plant at Minnedosa, Manitoba by the third quarter and be fully operational in the fourth quarter of 2007. In addition, we will continue to improve technology, appearance and product offerings at our marketing outlets and continue to optimize the number and location of our retail facilities.

6.0 Liquidity and Capital Resources

6.1 SUMMARY OF CASH FLOW

($ millions, except where indicated)	**2006**	2005	2004
Cash flow – operating activities	**$ 5,009**	$ 3,650	$ 2,304
– financing activities	**$ (1,626)**	$ (668)	$ 193
– investing activities	**$ (3,109)**	$ (2,814)	$ (2,497)
Debt to capital employed *(percent)*	**14.3**	20.1	25.8
Corporate reinvestment ratio *(percent)* [1]	**70**	80	110

(1) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

Cash Flow from Operating Activities

In 2006, cash generated by operating activities was $5,009 million, an increase of $1,359 million from the $3,650 million recorded in 2005. The higher cash from operating activities in 2006 was primarily due to higher earnings, partially offset by increased non-cash working capital associated with operating activities.

Cash Flow from (used for) Financing Activities

In 2006, cash used in financing activities amounted to $1,626 million. The cash used was composed of the repayment of long-term debt of $1,493 million and a $47 million settlement of a cross currency swap, dividends of $636 million, other costs of $1 million and a change of $678 million in non-cash working capital. Cash provided by financing activities in 2006 comprised $1,226 million issuance of long-term debt and $3 million of proceeds from the exercise of stock options. Debt issuances and repayments include multiple drawings and repayments under revolving debt facilities.

Husky's long-term debt balances were also reduced by $7 million during 2006, which mainly resulted from the narrowing of the exchange rate between Canadian and U.S. currencies.

Cash Flow used for Investing Activities

Cash used in investing activities amounted to $3,109 million in 2006, an increase of $295 million from the $2,814 million in 2005. Cash invested in 2006 was composed of capital expenditures of $3,171 million, partially offset by $34 million of proceeds from asset sales. Change in non-cash working capital and other adjustments amounted to $28 million used in investing activities.

6.2 WORKING CAPITAL COMPONENTS

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2006, our working capital deficiency was $495 million compared with $1.0 billion at December 31, 2005. It is not unusual for Husky to have working capital deficits at the end of a reporting period. These working capital deficits are mainly due to the large capital component in accounts payable, which is related largely to exploration and development expenditures. This is typical in the oil and gas industry, which is capital intensive. Settlement of these current liabilities is funded by cash provided by operating activities, and to the extent necessary, by bank borrowings.

($ millions)	**2006**	2005	Change	
Current assets				
Cash and cash equivalents	**$ 442**	$ 168	$ 274	Excess cash generated by White Rose
Accounts receivable	**1,284**	856	428	Repaid securitization program; higher crude oil prices
Inventories	**428**	471	(43)	Lower crude oil feedstock volumes in 2006
Prepaid expenses	**25**	40	(15)	Primarily Tucker construction advance in 2005
	2,179	1,535	644	
Current liabilities				
Accounts payable	**1,268**	1,213	(55)	Increased White Rose activity; refined product purchases in 2006
Accrued interest payable	**27**	41	14	Lower long-term debt due to repayments
Income taxes payable	**615**	164	(451)	2006 White Rose earnings; 2005 deferred earnings
Other accrued liabilities	**664**	892	228	Special dividend in 2005; higher stock-based compensation liability in 2006
Long-term debt due within one year	**100**	274	174	Repayment of 7.125% notes and 8.45% bonds
	2,674	2,584	(90)	
Working capital	**$ (495)**	$ (1,049)	$ 554	

Sources and Uses of Cash

Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's *upstream capital programs* are funded principally by cash provided from operating activities. During times of low oil and gas prices part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result, we frequently evaluate our options with respect to sources of long and short-term capital resources. In addition, we frequently evaluate hedging a portion of our production to protect cash flow in the event of commodity price declines.

The following illustrates our sources and uses of cash during the years ended December 31, 2006, 2005 and 2004:

Sources and Uses of Cash

($ millions)	**2006**	2005	2004
Cash sourced			
Cash flow from operations (1)	**$ 4,501**	$ 3,785	$ 2,197
Debt issue	**1,226**	3,235	2,200
Asset sales	**34**	74	36
Proceeds from exercise of stock options	**3**	6	18
Proceeds from monetization of financial instruments	**-**	39	8
	5,764	7,139	4,459
Cash used			
Capital expenditures	**3,171**	3,068	2,349
Corporate acquisitions	**-**	-	102
Debt repayment	**1,493**	3,502	1,941
Special dividend on common shares	**-**	424	229
Ordinary dividends on common shares	**636**	276	195
Settlement of asset retirement obligations	**36**	41	40
Settlement of cross currency swap	**47**	-	-
Other	**13**	32	24
	5,396	7,343	4,880
Net cash (deficiency)	**368**	(204)	(421)
Increase (decrease) in non-cash working capital	**(94)**	372	421
Increase in cash and cash equivalents	**274**	168	-
Cash and cash equivalents – beginning of year	**168**	-	-
Cash and cash equivalents – end of year	**$ 442**	$ 168	$ -

(1) Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.

Capital Structure

	December 31, 2006		
	Outstanding		Available
($ millions)	*(U.S. $)*	*(Cdn $)*	*(Cdn $)*
Short-term bank debt	$ -	$ -	$ 201
Long-term bank debt			
Syndicated credit facility	-	-	1,020
Bilateral credit facility	-	-	150
Medium-term notes	-	300	
Capital securities	225	262	
U.S. public notes	900	1,049	
Total short-term and long-term debt	$ 1,125	$ 1,611	$ 1,371
Common shares and retained earnings		$ 9,620	

As at December 31, 2006, our outstanding long-term debt totalled $1.6 billion, including amounts due within one year, compared with $1.9 billion at December 31, 2005.

On February 1, 2006, we redeemed our 8.45% senior secured bonds amounting to U.S. $85 million.

At December 31, 2006, we had no drawings under our $1.0 billion revolving syndicated credit facility. Interest rates under this facility vary and are based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain rating agencies to our senior unsecured debt. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than 3.5 times and a consolidated tangible net worth, as of December 31, 2006, of at least $5.1 billion.

At December 31, 2006, we had no drawings under our $150 million bilateral credit facilities. The terms of these facilities are substantially the same as the syndicated credit facility.

At December 31, 2006, we used $19 million in support of letters of credit under our $220 million in short-term borrowing facilities. The interest rates applicable to these facilities vary and are based on Bankers' Acceptance, U.S. LIBOR or prime rates. In addition, we had used $80 million under our dedicated letter of credit facilities.

Husky has an agreement to sell up to $350 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, plus a program fee to be paid on an ongoing basis. As at December 31, 2006, there were no sales of accounts receivable under this agreement. The arrangement matures on January 31, 2009.

Based on our 2007 commodity price forecast, we believe that our non-cancellable contractual obligations and other commercial commitments and our 2007 capital program will be funded by cash flow from operating activities and, to the extent required, by available credit facilities. In the event of significantly lower cash flow, we would be able to defer certain of our projected capital expenditures without penalty.

We declared dividends of $1.50 per share totalling $636 million in 2006. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.50 ($2.00 annually) per common share. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, our financial condition and other relevant factors.

Cash and cash equivalents at December 31, 2006 totalled $442 million compared with $168 million at the beginning of the year.

Credit Ratings

Husky's senior debt and capital securities have been rated investment grade by several rating agencies. These ratings are disclosed and explained in detail in our Annual Information Form.

6.3 CASH REQUIREMENTS

Contractual Obligations and Other Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations

Payments due by period *($ millions)*	Total	2007	2008–2009	2010–2011	Thereafter
Long-term debt and interest	$ 2,296	$ 209	$ 638	$ 136	$ 1,313
Operating leases	1,133	93	494	450	96
Firm transportation agreements	626	169	202	108	147
Unconditional purchase obligations (1)	4,201	2,144	1,908	136	13
Lease rentals and exploration work agreements	640	148	147	178	167
Engineering and construction commitments	140	140	–	–	–
	$ 9,036	$ 2,903	$ 3,389	$ 1,008	$ 1,736

(1) Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums and natural gas purchases. Approximately 72% of the total unconditional purchase obligations are in respect of processing and refined product purchase contracts.

Estimated Obligations Not Included in the Table

Asset retirement obligations ("ARO")

Husky currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004, with the adoption of the Canadian Institute of Chartered Accountants ("CICA") section 3110, "Asset Retirement Obligations," Husky records a separate liability for the fair value of its ARO. See Note 12 to the Consolidated Financial Statements.

Employee future benefits

Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition, Husky has a defined benefit pension plan for approximately 180 active employees and 480 retirees and beneficiaries. In 1991, admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan. See Note 16 to the Consolidated Financial Statements.

Other Obligations

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

6.4 OFF–BALANCE SHEET ARRANGEMENTS

We do not utilize off-balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

Accounts Receivable Securitization Program

In the ordinary course of business, we engage in the securitization of accounts receivable. The securitization program permits the sale of a maximum of $350 million of accounts receivable on a revolving basis. At December 31, 2006, there were no accounts receivable sold under the program. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party and in accordance with the agreement we must provide a loss reserve to replace defaulted receivables.

The securitization program provides us with cost-effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated, our liquidity would not be substantially reduced.

Standby Letters of Credit

In addition, from time to time, we issue letters of credit in connection with transactions in which the counterparty requires such security.

Derivative Instruments

We utilize derivative financial instruments in order to manage unacceptable risk. The derivative financial instruments currently outstanding are listed and discussed in Section 6.6, "Financial Risk and Risk Management."

6.5 TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, we paid approximately $10 million for office space in Western Canadian Place during 2004.

We did not have any customers that constituted more than 10% of total sales and operating revenues during 2006.

6.6 FINANCIAL RISK AND RISK MANAGEMENT

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to Section 2.5 under "The Business Environment in 2006." From time to time, we use derivative instruments to manage our exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of our oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas and purchases of electricity.

Power Consumption

During 2006, we received payments totalling $6 million on our power consumption hedges.

Foreign Currency Risk Management

At December 31, 2006, Husky had the following cross currency debt swaps in place:

U.S. $150 million at 6.25% swapped at $1.41 to $212 million at 7.41% until June 15, 2012.
U.S. $75 million at 6.25% swapped at $1.19 to $90 million at 5.65% until June 15, 2012.
U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

At December 31, 2006 the cost of a U.S. dollar in Canadian currency was $1.1653.

In 2006, the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $4 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling approximately $1 million in 2006. In 2004, Husky unwound its long-dated forwards resulting in a gain of $8 million, which was recognized into income during 2005 on the dates the underlying hedged transactions took place.

Interest Rate Risk Management

In 2006, interest rate risk management activities resulted in a decrease to interest expense of $1 million.

The cross currency swaps resulted in an addition to interest expense of $10 million in 2006.

We have interest rate swaps on $200 million of long-term debt, effective February 8, 2002, whereby 6.95% was swapped for Certificate of Deposit Offered Rate + 175 basis points until July 14, 2009. During 2006, these swaps resulted in an offset to interest expense amounting to $2 million.

The amortization of previous interest rate swap terminations resulted in an additional $9 million offset to interest expense in 2006.

6.7 OUTSTANDING SHARE DATA

Authorized:

unlimited number of common shares
unlimited number of preferred shares

Issued and outstanding: February 16, 2007

common shares	424,289,808
preferred shares	none
stock options	5,605,630
stock options exercisable	2,243,766

At February 16, 2007, 18,200,181 common shares were reserved for issuance under the stock option plan. Options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years.

7.0 Application of Critical Accounting Estimates

Husky's *Consolidated Financial* Statements have been prepared in accordance with Canadian GAAP. The significant accounting policies we use are disclosed in Note 3 to the Consolidated Financial Statements. Certain accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in this Management's Discussion and Analysis ("MD&A") to aid you in assessing the critical accounting policies and practices of Husky and the likelihood of materially different results being reported. We review our estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. Husky might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

7.1 FULL COST ACCOUNTING FOR OIL AND GAS ACTIVITIES

The indicated change in the following estimates will result in a corresponding increase in the amount of DD&A expense charged to income in a given period:

An increase in:

estimated costs to develop the proved undeveloped reserves;
estimated fair value of the ARO related to the oil and gas properties; and
estimated impairment of costs excluded from the DD&A calculation.

A decrease in:

previously estimated proved oil and gas reserves; and
estimated proved reserves added compared to capital invested.

Depletion Expense

In accordance with the full cost method of accounting, all costs associated with exploration and development are capitalized on a country-by-country basis. The aggregate of capitalized costs, net of accumulated DD&A, plus the estimated future costs required to develop the proved undeveloped oil and gas reserves, less estimated equipment salvage values, is charged to income as the reserves are produced over time using the unit of production method based on proved oil and gas reserves.

Withheld Costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Ceiling Test

The ceiling test requires each cost centre's capitalized costs be tested for recoverability. The test uses the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs. When the carrying amount of a cost centre is not recoverable, the cost centre is *written down to its fair value. Fair* value is estimated using present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining estimated cash flows.

7.2 IMPAIRMENT OF LONG-LIVED ASSETS

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

7.3 FAIR VALUE OF DERIVATIVE INSTRUMENTS

Periodically, we utilize financial derivatives to manage market risk. The purpose of the derivative is to provide an element of stability to our cash flow in a volatile environment. We disclose the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). Refer to the description of FAS 133 in Note 19 to the Consolidated Financial Statements.

The estimation of the fair value of derivatives requires considerable judgment. The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location.

The estimate of fair value for interest rate and foreign currency hedges is determined largely through forward market prices and compared with quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of Husky. In this event our policy would be modified.

7.4 ASSET RETIREMENT OBLIGATIONS

We have significant obligations to remove tangible assets and restore land after operations cease and we retire or relinquish the asset. The ARO relates to all of our business operations, however, approximately 90% of the liability relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and subsea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often require interpretation. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and stakeholder considerations.

The ARO rules require that an asset retirement obligation associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying cost of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the initial fair value of the ARO is recognized over the useful life of the asset. The initial fair value of the ARO is accreted to its expected settlement date. The accretion amount is expensed as a cost of operating and is added to the ARO liability. The fair value of the ARO is measured using expected future cash outflows discounted at our credit adjusted risk free interest rate.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, future third-party pricing, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the tangible asset balance.

7.5 LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINGENT MATTERS

We are required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine if the loss can reasonably be estimated. When the loss is determined it is charged to earnings. Husky's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

7.6 INCOME TAX ACCOUNTING

The determination of our income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

7.7 BUSINESS COMBINATIONS

Over recent years, Husky has grown considerably through combining with other businesses. Husky acquired Temple Exploration Inc. in 2004 and Marathon Canada Limited in 2003. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the net assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties relies mainly on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described in Section 4.1, "Upstream" under the caption "Oil and Gas Reserves" but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition, this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

7.8 GOODWILL

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's net assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. In accordance with the issuance of FASB Statement No. 142 and CICA section 3062, "Goodwill and Other Intangible Assets," goodwill is no longer amortized but assessed annually for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

7.9 VARIABLE INTEREST ENTITIES

The principles of consolidation govern which entities and their accounts must be included in our consolidated financial statements. In 2003, the FASB issued additional guidance in respect of those principles in response to perceived abuse of special purpose entities that were designed to hold assets and liabilities and were not included in the consolidated financial statements of the reporting enterprise because they did not hold voting control of the special purpose entity. The CICA followed with similar guidance in 2004. These special purpose entities are now called variable interest entities. A variable interest entity is a legal entity that lacks sufficient controlling equity at risk to enable it to continue to finance its operations and absorb future potential losses without additional subordinated support. Reporting enterprises must now determine if they are the primary beneficiaries of any variable interest entities that they may have a contractual arrangement with. The process is complex and requires management's judgment to determine if any variable interest entities are required to be consolidated.

We review our contractual arrangements annually to determine if any arrangements constitute a potential financial interest in a variable interest entity.

8.0 New Accounting Standards

8.1 CANADIAN ACCOUNTING

Non-monetary Transactions

Effective January 1, 2006, we began to apply the recommendations pursuant to CICA section 3831, "Non-monetary Transactions." The recommendations of section 3831 require that all non-monetary transactions be measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business.

8.2 U.S. ACCOUNTING

Accounting for Defined Benefit Pension Plans and Other Post-retirement Benefit Plans

In September 2006, the FASB issued FAS 158, "Employers Accounting for Defined Benefit Pension Plans and Other Post-retirement Benefit Plans – an Amendment of FASB Statements No. 87, 88, 106 and 132(R)." FAS 158 requires the recognition of the underfunded or overfunded status of each defined benefit pension plan and other post-retirement benefit plan as a liability or asset. Changes in the funded status are recorded through accumulated other comprehensive income as a separate component of shareholders' equity in the year in which the changes occur. The impact of this standard on our U.S. GAAP financial statements is disclosed in Note 19 to the Consolidated Financial Statements.

Accounting for Purchases and Sales of Inventory with the Same Counterparty

In September 2005, the Emerging Issues Task Force ("EITF") redeliberated EITF 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty". In arrangements whereby one inventory transaction is legally contingent upon the performance of another inventory transaction with the same counterparty, including buy/sell transactions, these transactions are considered a single exchange transaction subject to Accounting Principles Board Opinion No. 29 "Accounting for Non-monetary Transactions", when the transactions are entered into "in contemplation" of one another. EITF 04-13 clarifies that non-monetary exchanges whereby an entity transfers finished goods inventory in exchange for the receipt of raw materials or work-in-progress inventory within the same line of business is not an exchange transaction to facilitate sales to customers. These non-monetary exchanges are required to be recognized at fair value if reasonably determinable and the transaction has commercial substance. All other non-monetary exchanges of inventory within the same line of business are to be recognized at the carrying amount of the inventory transferred. EITF 04-13 is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first interim or annual reporting period beginning after March 15, 2006. The application of EITF 04-13 did not have a material impact on the financial statements.

Quantifying Financial Statement Misstatements

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements". SAB 108 was issued by the SEC because of an apparent diversity in the practice of registrants quantifying misstatements from prior years and assessing the effect on current year financial statements. SAB 108 requires registrants to adjust their financial statements if the misstatement quantified under the new approach, including prior-year effects, results in a material error in the current year. This adjustment is required even if misstatements of prior years are considered immaterial. If registrants followed an acceptable approach to quantifying financial statement misstatements in the past, the SEC will not require these registrants to restate prior years' historical financial statements. Instead, these registrants will be able to report the cumulative effect of adopting the new approach as an adjustment to the current year's beginning retained earnings balance. If entities correct prior-year financial statements for immaterial errors, this guidance does not require amendments to previously filed reports. Instead, this correction can be made the next time the entity files the prior year financial statements. SAB 108 is effective for fiscal years ending after November 15, 2006. The application of SAB 108 did not have an impact on the financial statements.

9.0 Pending Accounting Standards

9.1 CANADIAN ACCOUNTING PRONOUNCEMENTS

Financial Instruments

In April 2005, the CICA issued three new Handbook sections that deal with the recognition and measurement of financial instruments:

Section 1530, "Comprehensive Income;"

Section 3855, "Financial Instruments – Recognition and Measurement;" and

Section 3865, "Hedges."

The new standards are an attempt to harmonize Canadian GAAP with U.S. GAAP. Initial measurement of all financial instruments is to be based on their fair values. The subsequent measurement of the financial instrument will depend on whether it is classified as a loan or receivable; held to maturity investment; available for sale financial asset; held for trading asset or liability; or, other financial liability. Available for sale financial assets and held for trading assets or liabilities are measured at fair value on an ongoing basis. The other financial instruments are recognized at amortized cost using the effective interest method. The gains and losses on available for sale financial assets will be recognized in other comprehensive income and are transferred to net income when the asset is derecognized. The gains and losses on held for trading financial instruments are recognized immediately in net income.

Other comprehensive income is a new equity category where revenues, expenses, gains and losses are temporarily presented outside of net income but included in comprehensive income. Unrealized gains or losses on qualifying hedging instruments and available for sale financial assets are included in other comprehensive income and reclassified to net income when required by GAAP.

Hedge accounting continues to be optional and the new Handbook section provides detailed guidance on the application of hedge accounting and the required disclosures.

These new standards are effective for fiscal years beginning on or after January 1, 2007. The impact of these standards is disclosed in Note 18 to the Consolidated Financial Statements.

Financial Instruments – Disclosures and Presentation

In December 2006, the Canadian Accounting Standards Board ("AcSB") issued CICA section 3862, "Financial Instruments – Disclosures" and CICA section 3863, "Financial Instruments – Presentation" to replace CICA section 3861, "Financial Instruments – Disclosure and Presentation." These standards were issued to converge with recently issued International Financial Reporting Standard ("IFRS") 7. The presentation requirements under section 3863 are unchanged from section 3861. The disclosure requirements under section 3862 have been revised and enhanced. Upon application of section 3862, a reader of our financial statements will be afforded information to evaluate the effect of financial instruments on our financial position and the amount, timing and uncertainty of cash flows associated with financial instruments. Specifically, an increased emphasis has been placed on disclosures regarding the risks associated with recognized and unrecognized financial instruments and how these risks are managed. The disclosures will include both qualitative information about our objectives, policies and processes for risk management and quantitative information that will provide information about the extent to which we are exposed to risk. CICA section 3862 and section 3863 are effective for fiscal years beginning on or after October 1, 2007.

Capital Disclosures

In December 2006, the AcSB issued CICA section 1535, "Capital Disclosures." This standard was issued to converge with amendments to International Accounting Standard 1. Upon application of these recommendations, readers of financial statements will be provided information pertinent to our objectives, policies and processes for managing capital. We will also disclose quantitative data regarding what we consider capital and whether we are in compliance with all externally imposed capital requirements and the consequences of non-compliance. CICA section 1535 is effective for fiscal years beginning on or after October 1, 2007.

Accounting Changes

In July 2006, the AcSB issued a revised CICA section 1506, "Accounting Changes." These amendments were made to harmonize section 1506 with current IFRS. The changes covered by this section include changes in accounting policy, changes in accounting estimates and correction of errors. Under CICA section 1506, voluntary changes in accounting policy are only permitted if they result in financial statements that provide more reliable and relevant information. When a change in accounting policy is made, this change is applied retrospectively unless impractical. Changes in accounting estimates are generally applied prospectively and material prior period errors are corrected retrospectively. This section also outlines additional disclosure requirements when accounting changes are applied including justification for voluntary changes, complete description of the policy, primary source of GAAP and detailed effect on financial statement line items. CICA section 1506 is effective for fiscal years beginning on or after January 1, 2007.

Determining the Variability to be Considered in Applying AcG-15

In September 2006, the Canadian Emerging Issues Committee ("EIC") issued Abstract No. 163, "Determining the Variability to be Considered in Applying AcG-15" ("EIC-163"). This abstract was issued based on the previous issuance by the U.S. FASB of FASB Interpretation Number ("FIN") 46(R)-6, which was issued to remedy an apparent diversity in applying the requirements of FIN 46(R). EIC-163 provides guidance in the interpretation of variability that should be considered when determining:

- when an entity is a variable interest entity;
- which interests are variable interests in the entity; and
- which party, if any, is the primary beneficiary of the variable interest entity.

The appropriate process results in the determination of whether we are a primary beneficiary and therefore must consolidate a variable interest entity. The provisions of this abstract are applied prospectively. EIC-163 is effective for all new and reconsidered entities we are involved with and all entities previously considered under AcG-15, beginning the first reporting period after January 1, 2007.

9.2 U.S. ACCOUNTING PRONOUNCEMENTS

Fair Value Measurement

In September 2006, the FASB issued FAS 157, "Fair Value Measurements", which defines fair value, establishes a framework for measuring fair value in U.S. GAAP pronouncements and expands the disclosure requirements for fair value measurements. Prior to FAS 157, various definitions of fair value existed with limited guidance for application of these definitions in U.S. GAAP. Fair value under this standard is focused on a market-based measurement as opposed to an entity-specific measurement. This standard establishes a fair value hierarchy that distinguishes between market participant assumptions based on market data obtained from independent sources and the reporting entity's own assumptions about the market. The provisions of this Statement are applied prospectively with certain exceptions that require retrospective application. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We will consider this fair value measurement framework when applying other U.S. GAAP pronouncements where fair value is a consideration.

Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." This interpretation clarifies the accounting for the uncertainty in income taxes recognized in accordance with FAS 109. FIN 48 establishes a two-step process for the evaluation of a tax position taken or expected to be taken in a tax return. The first step recognizes whether or not a tax position is sustainable based on a "more-likely-than-not" determination. The second step measures the amount of tax benefit to recognize in the financial statements if the tax position meets the more-likely-than-not threshold. Under FIN 48, the tax position is measured as the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN 48 is effective for fiscal years beginning after December 15, 2006. We are currently determining the impact of this issue.

Accounting for Planned Major Maintenance Activities

In September 2006, the FASB issued a Staff Position in respect of accounting for major planned maintenance, which will prohibit the cost of major planned maintenance from being accrued as a liability over several reporting periods before the maintenance is performed or over interim reporting periods within the annual period in which the cost is expected to be incurred. This will become effective on January 1, 2007. This FASB Staff Position will not affect our financial statements.

10.0 Forward-looking Statements

Certain statements in this MD&A and in the Annual Report that this MD&A forms a part of are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as: "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, forward-looking statements include: our general strategic plans, our production for the Tucker in-situ oil sands project, our Sunrise oil sands project design, our exploration and development plans, including planned exploration and development for Western Canada, on the East coast of Canada, in the offshore basins of China and Indonesia and in the oil sands region of Alberta, the percentage of our expected production attributable to conventional oil equivalent production from the Western Canadian Sedimentary Basin, our plans to replace our conventional production, our planned capital expenditures in 2007 and the type of such expenditure, the rate at which we will ramp up production at Tucker, the timing of our plan to complete Sunrise front-end engineering, our business plans for the Midstream and Refined Products, our production guidance, reserve estimates and estimates of discovered resources and contingent resources. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this MD&A. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to

- adequacy of and fluctuations in oil and natural gas prices;
- demand for our products and services and the cost of required inputs;
- our ability to replace our reserves;
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy;
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures, natural disasters and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable;
- actions by governmental authorities, including changes in environmental and other regulations that may impose restrictions in areas where we operate; and
- the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

11.0 Oil and Gas Reserve Reporting

Disclosure of Proved Oil and Gas Reserves and Other Oil and Gas Information

Husky's disclosure of proved oil and gas reserves and other information about its oil and gas activities has been made based on reliance of an exemption granted by Canadian Securities Administrators. The exemption permits Husky to make these disclosures in accordance with requirements in the United States. These requirements and, consequently, the information presented may differ from Canadian requirements under National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities". The proved oil and gas reserves disclosed in this MD&A have been evaluated using the United States standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934. The probable oil and gas reserves disclosed in this MD&A have been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101.

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Volumes of oil and gas classified as resources in this document have not met all the requirements outlined by the SEC for proved and NI 51-101 for probable and possible to be classified as reserves. These requirements may include, but are not limited to; drilling requirements, testing requirements, regulatory requirements, infrastructure and market considerations, commitment to develop and economic requirements. Once all the requirements are met the Company will reclassify the volumes to reserves in future disclosures.

Cautionary Note to U.S. Investors

The United States Securities and Exchange Commission permits U.S. oil and gas companies, in their filings with the SEC, to disclose only proved reserves, that is reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. We use certain terms in this MD&A and in the Annual Report that this MD&A forms a part of, such as "probable reserves", "possible reserves", "discovered resources" and "contingent resources", that the SEC's guidelines strictly prohibit in filings with the SEC by U.S. oil and gas companies. U.S. investors should refer to our Annual Report on Form 40-F available from us or the SEC for further reserve disclosure.

12.0 Non-GAAP Measures

Disclosure of Cash Flow from Operations

This MD&A contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow – operating activities", as determined in accordance with GAAP as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items. The following table shows the reconciliation of cash flow from operations to cash flow – operating activities for the years ended December 31:

($ millions)		**2006**	2005	2004
Non-GAAP	Cash flow from operations	**$ 4,501**	$ 3,785	$ 2,197
	Settlement of asset retirement obligations	**(36)**	(41)	(40)
	Change in non-cash working capital	**544**	(72)	169
GAAP	Cash flow – operating activities	**$ 5,009**	$ 3,672	$ 2,326

13.0 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This MD&A is intended to provide an explanation of financial and operational performance compared with prior periods and our prospects and plans. It provides additional information that is not contained in our financial statements.

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 26, 2007. Any events subsequent to that date could conceivably materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. The readers are also encouraged to refer to Husky's interim reports filed in 2006, which contain MD&A and Consolidated Financial Statements, and Husky's Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.ca.

Use of Pronouns and Other Terms

"We", "our", "us", "Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2006 and 2005 and Husky's financial position as at December 31, 2006 and at December 31, 2005.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change their decision to buy, sell or hold the securities of Husky.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with GAAP in Canada. Significant differences between Canadian and United States GAAP are disclosed in Note 19 to the Consolidated Financial Statements.
- Currency is presented in millions of Canadian dollars ("C$").
- Gross production and reserves are Husky's working interest prior to deduction of royalty volume.
- Prices are presented before the effect of hedging.
- Light crude oil is 30° API and above.
- Medium crude oil is 21° API and above but below 30° API.
- Heavy crude oil is above 10° API but below 21° API.
- Bitumen is 10° API and below.

Abbreviations

bbls	*barrels*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
GJ	*gigajoule*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
MW	*megawatt*
MWh	*megawatt hour*
NGL	*natural gas liquids*
WTI	*West Texas Intermediate*
NYMEX	*New York Mercantile Exchange*
NIT	*NOVA Inventory Transfer*
LIBOR	*London Interbank Offered Rate*
CDOR	*Certificate of Deposit Offered Rate*
SEDAR	*System for Electronic Document Analysis and Retrieval*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front-end engineering design*
OPEC	*Organization of Petroleum Exporting Countries*
WCSB	*Western Canada Sedimentary Basin*
SAGD	*Steam-assisted gravity drainage*

Terms

Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
Carbonate	*Sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite) which forms many petroleum reservoirs*
Capital Employed	*Short- and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Coalbed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Dated Brent	*Prices which are dated less than 15 days prior to loading for delivery*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Diluent	*A light liquid hydrocarbon, usually condensate, added to heavy oil to permit transportation through a pipeline*
Equity	*Shares and retained earnings*
Feedstock	*Raw materials which are processed into petroleum products*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Section	*Area that is one square mile or 640 acres*
Surfactant	*A substance that tends to reduce the surface tension of a liquid in which it is dissolved*
Total Debt	*Long-term debt including current portion and bank operating loans*

Oil and Gas Reserves Definitions

Proved reserves have been estimated in accordance with the SEC definition set out in Rule 4-10(a) of Regulation S-X under the Securities Exchange Act of 1934 as follows: Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Proved Developed reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped reserves are those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Inclusion of reserves on undrilled acreage is limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only if it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Probable reserves are those additional reserves that are less certain to be recovered then proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

Possible reserves are those reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Original resources are those quantities of oil and gas estimated to exist originally in natural occurring accumulations, both discovered and undiscovered.

Discovered resources are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into economic and uneconomic categories, with the estimated future recoverable portion classified as reserves and contingent resources, respectively.

Contingent resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but are not currently economic.

14.0 Controls and Procedures

Disclosure Controls and Procedures

Husky's management, with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2006, and has concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control Over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management is responsible for establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2006, management assessed the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective and that there are no material weaknesses in Husky's internal control over financial reporting that have been identified by management.
4) KPMG LLP, who has audited the consolidated financial statements of Husky for the year ended December 31, 2006, has also issued a report on the financial statements and internal controls under Auditing Standard No. 2 of the Public Company Accounting Oversight Board (United States). This report is located with Husky's Consolidated Financial Statements and Auditors' Report to Shareholders for the Year Ended December 31, 2006.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2006, that have materially affected, or are reasonably likely to materially affect its internal control over financial reporting.

Management's Report

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this financial document.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this financial document has been prepared on a basis consistent with that in the consolidated financial statements.

Husky Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management evaluation concluded that our internal control over financial reporting was effective as of December 31, 2006. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board. The Committee is also responsible for the appointment of the external auditors for the Company.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

John C. S. Lau
President & Chief Executive Officer

Calgary, Alberta, Canada
February 5, 2007

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Husky Energy Inc. ("the Company") as at December 31, 2006, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the year ended December 31, 2006, we also conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 5, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Chartered Accountants
Calgary, Alberta, Canada
February 5, 2007

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Husky Energy Inc.

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting, that Husky Energy Inc. ("the Company") maintained effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the year ended December 31, 2006, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated February 5, 2007 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants
Calgary, Alberta, Canada
February 5, 2007

Consolidated Balance Sheets

As at December 31 *(millions of dollars)*	2006	2005	2004
ASSETS			
Current assets			
Cash and cash equivalents	**$ 442**	$ 168	$ –
Accounts receivable *(note 4)*	**1,284**	856	446
Inventories *(note 5)*	**428**	471	274
Prepaid expenses	**25**	40	52
	2,179	1,535	772
Property, plant and equipment, net *(notes 1, 6)*	**15,550**	13,959	12,193
Goodwill *(note 7)*	**160**	160	160
Other assets *(note 11)*	**44**	62	108
	$ 17,933	$ 15,716	$ 13,233
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank operating loans *(note 9)*	**$ -**	$ -	$ 101
Accounts payable and accrued liabilities *(note 10)*	**2,574**	2,310	1,439
Long-term debt due within one year *(note 11)*	**100**	274	56
	2,674	2,584	1,596
Long-term debt *(note 11)*	**1,511**	1,612	2,047
Other long-term liabilities *(note 12)*	**756**	730	632
Future income taxes *(note 13)*	**3,372**	3,270	2,758
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Common shares *(note 15)*	**3,533**	3,523	3,506
Retained earnings	**6,087**	3,997	2,694
	9,620	7,520	6,200
	$ 17,933	$ 15,716	$ 13,233

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

John C. S. Lau
Director

R.D. Fullerton
Director

Consolidated Statements of Earnings

Year ended December 31 *(millions of dollars, except per share amounts)*	**2006**	2005	2004
Sales and operating revenues, net of royalties	**$ 12,664**	$ 10,245	$ 8,440
Costs and expenses			
Cost of sales and operating expenses *(note 12)*	**7,169**	5,917	5,706
Selling and administration expenses	**162**	138	135
Stock-based compensation *(note 15)*	**138**	171	67
Depletion, depreciation and amortization *(notes 1, 6)*	**1,599**	1,256	1,179
Interest – net *(note 11)*	**92**	32	60
Foreign exchange *(note 11)*	**(24)**	(31)	(120)
Other – net	**22**	(50)	8
	9,158	7,433	7,035
Earnings before income taxes	**3,506**	2,812	1,405
Income taxes *(note 13)*			
Current	**678**	297	302
Future	**102**	512	97
	780	809	399
Net earnings	**$ 2,726**	$ 2,003	$ 1,006
Earnings per share *(note 15)*			
Basic and diluted	**$ 6.43**	$ 4.72	$ 2.37

Consolidated Statements of Retained Earnings

Year ended December 31 *(millions of dollars)*	**2006**	2005	2004
Beginning of year	**$ 3,997**	$ 2,694	$ 2,156
Net earnings	**2,726**	2,003	1,006
Dividends on common shares *(note 15)*			
Ordinary	**(636)**	(276)	(195)
Special	**–**	(424)	(229)
Stock-based compensation – retroactive adoption *(note 15)*	**–**	–	(44)
End of year	**$ 6,087**	$ 3,997	$ 2,694

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

Year ended December 31 *(millions of dollars)*	**2006**	2005	2004
Operating activities			
Net earnings	**$ 2,726**	$ 2,003	$ 1,006
Items not affecting cash			
Accretion *(note 12)*	**45**	33	27
Depletion, depreciation and amortization	**1,599**	1,256	1,179
Future income taxes	**102**	512	97
Foreign exchange	**(3)**	(37)	(124)
Other	**32**	18	12
Settlement of asset retirement obligations	**(36)**	(41)	(40)
Change in non-cash working capital *(note 8)*	**544**	(94)	147
Cash flow – operating activities	**5,009**	3,650	2,304
Financing activities			
Bank operating loans financing – net	**–**	(101)	(4)
Long-term debt issue	**1,226**	3,235	2,200
Long-term debt repayment	**(1,493)**	(3,401)	(1,937)
Settlement of cross currency swap	**(47)**	–	–
Debt issue costs	**–**	–	(5)
Proceeds from exercise of stock options	**3**	6	18
Proceeds from monetization of financial instruments	**–**	39	8
Dividends on common shares	**(636)**	(700)	(424)
Other	**(1)**	(1)	–
Change in non-cash working capital *(note 8)*	**(678)**	255	337
Cash flow – financing activities	**(1,626)**	(668)	193
Available for investing	**3,383**	2,982	2,497
Investing activities			
Capital expenditures	**(3,171)**	(3,068)	(2,349)
Corporate acquisitions	**–**	–	(102)
Asset sales	**34**	74	36
Other	**(12)**	(31)	(19)
Change in non-cash working capital *(note 8)*	**40**	211	(63)
Cash flow – investing activities	**(3,109)**	(2,814)	(2,497)
Increase in cash and cash equivalents	**274**	168	–
Cash and cash equivalents at beginning of year	**168**	–	–
Cash and cash equivalents at end of year	**$ 442**	$ 168	$ –

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1. Segmented Financial Information

	Upstream			Midstream		
				Upgrading		
Year ended December 31	**2006**	2005	2004	**2006**	2005	2004
Sales and operating revenues, net of royalties	**$ 5,772**	$ 4,367	$ 3,120	**$ 1,679**	$ 1,488	$ 1,058
Costs and expenses						
Operating, cost of sales, selling and general	**1,321**	1,050	967	**1,273**	1,018	884
Depletion, depreciation and amortization	**1,476**	1,144	1,077	**24**	21	19
Interest – net	**-**	-	-	**-**	-	-
Foreign exchange	**-**	-	-	**-**	-	-
	2,797	2,194	2,044	**1,297**	1,039	903
Earnings (loss) before income taxes	**2,975**	2,173	1,076	**382**	449	155
Current income taxes	**519**	215	211	**53**	16	-
Future income taxes	**161**	434	152	**44**	120	43
Net earnings (loss)	**$ 2,295**	$ 1,524	$ 713	**$ 285**	$ 313	$ 112
Capital employed – As at December 31 (2)	**$ 9,482**	$ 8,741	$ 7,628	**$ 553**	$ 510	$ 481
Property, plant and equipment – As at December 31						
Cost						
Canada	**$21,019**	$18,512	$16,023	**$ 1,390**	$ 1,205	$ 1,084
International	**751**	655	587	**-**	-	-
	$21,770	$19,167	$16,610	**$ 1,390**	$ 1,205	$ 1,084
Accumulated depletion, depreciation and amortization						
Canada	**$ 8,141**	$ 6,729	$ 5,722	**$ 455**	$ 430	$ 409
International	**404**	354	311	**-**	-	-
	$ 8,545	$ 7,083	$ 6,033	**$ 455**	$ 430	$ 409
Net						
Canada	**$12,878**	$11,783	$10,301	**$ 935**	$ 775	$ 675
International	**347**	301	276	**-**	-	-
	$13,225	$12,084	$10,577	**$ 935**	$ 775	$ 675
Capital expenditures – Year ended December 31 (3)	**$ 2,627**	$ 2,730	$ 2,157	**$ 184**	$ 120	$ 62
Total assets – As at December 31 (4)						
Canada	**$13,540**	$12,559	$10,750	**$ 992**	$ 844	$ 708
International	**380**	328	275	**-**	-	-
	$13,920	$12,887	$11,025	**$ 992**	$ 844	$ 708

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) Defined as short- and long-term debt and shareholders' equity.

(3) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(4) Includes goodwill on corporate acquisitions related to Upstream.

Midstream			**Refined Products**			**Corporate and Eliminations** [1]			**Total**		
Infrastructure and Marketing											
2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
$ 9,559	$ 7,383	$ 6,126	**$ 2,575**	$ 2,345	$ 1,797	**$(6,921)**	$(5,338)	$(3,661)	**$12,664**	$10,245	$ 8,440
9,258	7,084	5,914	**2,381**	2,169	1,694	**(6,742)**	(5,145)	(3,543)	**7,491**	6,176	5,916
24	21	21	**48**	47	38	**27**	23	24	**1,599**	1,256	1,179
–	–	–	**–**	–	–	**92**	32	60	**92**	32	60
–	–	–	**–**	–	–	**(24)**	(31)	(120)	**(24)**	(31)	(120)
9,282	7,105	5,935	**2,429**	2,216	1,732	**(6,647)**	(5,121)	(3,579)	**9,158**	7,433	7,035
277	278	191	**146**	129	65	**(274)**	(217)	(82)	**3,506**	2,812	1,405
79	(14)	31	**19**	(3)	11	**8**	83	49	**678**	297	302
1	110	32	**21**	50	13	**(125)**	(202)	(143)	**102**	512	97
$ 197	$ 182	$ 128	**$ 106**	$ 82	$ 41	**$ (157)**	$ (98)	$ 12	**$ 2,726**	$ 2,003	$ 1,006
$ 843	$ 390	$ 426	**$ 561**	$ 481	$ 360	**$ (208)**	$ (716)	$ (491)	**$11,231**	$ 9,406	$ 8,404
$ 750	$ 683	$ 647	**$ 1,344**	$ 1,063	$ 878	**$ 298**	$ 257	$ 232	**$24,801**	$21,720	$18,864
–	–	–	**–**	–	–	**–**	–	–	**751**	655	587
$ 750	$ 683	$ 647	**$ 1,344**	$ 1,063	$ 878	**$ 298**	$ 257	$ 232	**$25,552**	$22,375	$19,451
$ 270	$ 247	$ 226	**$ 525**	$ 476	$ 432	**$ 207**	$ 180	$ 158	**$ 9,598**	$ 8,062	$ 6,947
–	–	–	**–**	–	–	**–**	–	–	**404**	354	311
$ 270	$ 247	$ 226	**$ 525**	$ 476	$ 432	**$ 207**	$ 180	$ 158	**$10,002**	$ 8,416	$ 7,258
$ 480	$ 436	$ 421	**$ 819**	$ 587	$ 446	**$ 91**	$ 77	$ 74	**$15,203**	$13,658	$11,917
–	–	–	**–**	–	–	**–**	–	–	**347**	301	276
$ 480	$ 436	$ 421	**$ 819**	$ 587	$ 446	**$ 91**	$ 77	$ 74	**$15,550**	$13,959	$12,193
$ 68	$ 37	$ 31	**$ 285**	$ 191	$ 106	**$ 37**	$ 21	$ 23	**$ 3,201**	$ 3,099	$ 2,379
$ 1,329	$ 866	$ 746	**$ 1,114**	$ 834	$ 625	**$ 578**	$ 285	$ 129	**$17,553**	$15,388	$12,958
–	–	–	**–**	–	–	**–**	–	–	**380**	328	275
$ 1,329	$ 866	$ 746	**$ 1,114**	$ 834	$ 625	**$ 578**	$ 285	$ 129	**$17,933**	$15,716	$13,233

Note 2. Nature of Operations and Organization

Husky Energy Inc. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada.

Management has segmented the Company's business based on differences in products and services and management responsibility. The Company's business is conducted predominantly through three major business segments – upstream, midstream and refined products.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada, offshore China and offshore Indonesia.

Midstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (upgrading); marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke; and pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (infrastructure and marketing).

Refined products include refining of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products.

Note 3. Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

These financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 19, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

Substantially all of the Company's upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand less outstanding cheques and deposits with a maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand, the excess is reported in bank operating loans.

c) Inventory Valuation

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

d) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical activity, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on gross proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. Costs subject to depletion and depreciation include both the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20% or more.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until proved developed reserves have been attributed to a portion of the property or the property is determined to be impaired.

Impairment losses are recognized when the carrying amount of a cost centre exceeds the sum of:

- the undiscounted cash flow expected to result from production from proved reserves based on forecast oil and gas prices and costs;
- the costs of unproved properties, less impairment; and
- the costs of major development projects, less impairment.

The amount of impairment loss is determined to be the amount by which the carrying amount of the cost centre exceeds the sum of:

- the fair value of proved and probable reserves; and
- the cost, less impairment, of unproved properties and major development projects that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets which range from five to 25 years. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Certain turnaround costs are deferred to other assets when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Asset Retirement Obligations

The recognition of the fair value of obligations associated with the retirement of tangible long-lived assets is recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Retirement expenditures are charged to the accumulated liability as incurred.

iv) Capitalized Interest

Interest is capitalized on significant major capital projects based on the Company's long-term cost of borrowing.

e) Impairment or Disposal of Long-lived Assets

An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) the entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on at least an annual basis or sooner if there are indicators of impairment. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair value of the reporting unit is compared with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value, determined based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes. The Company may choose to designate derivative financial instruments as hedges for accounting purposes.

When designated, at the inception of the hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between hedged items and hedging items and the method for testing the effectiveness of the hedge which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into power price contracts to hedge anticipated purchases of electricity to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream operating expenses as the related purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under current or non-current assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The forward premium or discount on the foreign exchange contract is amortized as an adjustment to interest expense over the term of the contract.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective as a hedge prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized in income. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized in earnings.

Fair values of the financial instruments are based on quoted market prices where available. The fair values of swaps and forwards are based on forward market prices. If a forward price is not available for a commodity based forward, a forward price is estimated using an existing forward price adjusted for quality or location.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted.

j) Non-monetary Transactions

Non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business.

k) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

l) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings.

m) Stock-based Compensation

The Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock-based Compensation and Other Stock-based Payments," retroactively without restatement of prior periods. In accordance with the Company's stock option plan, common share options may be granted to directors, officers and certain other employees. The recommendations require the Company to record compensation expense over the vesting period based on the fair value of options granted.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital. Accrued compensation for an option that is forfeited is adjusted to earnings by decreasing the compensation cost in the period of forfeiture.

n) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. However, since the Company has a tandem stock option plan and accrues a liability for expected cash settlements, the potential common shares issuable upon exercise associated with the stock options are not included in diluted common shares outstanding. Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

o) Reclassification

Certain prior years' amounts have been reclassified to conform with current presentation.

Note 4. Accounts Receivable

	2006	2005	2004
Trade receivables	**$ 1,286**	$ 854	$ 448
Allowance for doubtful accounts	**(10)**	(10)	(10)
Other	**8**	12	8
	$ 1,284	$ 856	$ 446

Sale of Accounts Receivable

As at December 31, 2006, the Company's ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party was $350 million. As at December 31, 2006, no accounts receivable had been sold under the program (2005 and 2004 – $350 million). The agreement includes a program fee. The average effective rate for 2006 was approximately 4.1% (2005 – 3.0%; 2004 – 2.6%).

Proceeds from revolving sales between the third party and the Company in 2006 totalled approximately $3.1 billion (2005 – $3.4 billion; 2004 – $2.5 billion).

Note 5. Inventories

	2006	2005	2004
Crude oil and refined petroleum products	**$ 208**	$ 241	$ 159
Natural gas	**193**	207	100
Materials, supplies and other	**27**	23	15
	$ 428	$ 471	$ 274

Note 6. Property, Plant and Equipment

Refer to note 1, Segmented Financial Information, which presents the Company's property, plant and equipment by segment.

Administrative costs related to exploration and development activities capitalized in 2006 were $68 million (2005 – $61 million; 2004 – $40 million).

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2006	2005	2004
Canada	**$ 1,932**	$ 2,317	$ 2,399
International	**165**	127	129
	$ 2,097	$ 2,444	$ 2,528

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2006 were:

Canada	2007	2008	2009	2010	2011	Price increase 2011 to 2026 *(percent)*
Crude oil *($/bbl)*	$ 56.91	$ 51.90	$ 44.90	$ 41.60	$ 42.58	68
Natural gas *($/mcf)*	7.71	7.70	7.18	6.86	6.87	35

Subsequent to December 31, 2006, the Company entered into an agreement to dispose of certain non-core properties in Western Canada for total proceeds of $339 million. This transaction is expected to close in the first quarter of 2007.

Note 7. Corporate Acquisition

Effective July 15, 2004, the Company acquired all of the issued and outstanding shares of Temple Exploration Inc. ("Temple") for total cash consideration of $102 million. The results of Temple are included in the consolidated financial statements of the Company from its acquisition date.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Temple on its acquisition date was as follows:

Net assets acquired	
Working capital	$ (17)
Property, plant and equipment	138
Goodwill [(1)]	20
Future income taxes	(39)
	$ 102

(1) Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.

Note 8. Cash Flows – Change in Non-cash Working Capital

a) Change in non-cash working capital was as follows:

	2006	2005	2004
Decrease (increase) in non-cash working capital			
Accounts receivable	**$ (428)**	$ (410)	$ 209
Inventories	**43**	(197)	(77)
Prepaid expenses	**14**	17	(12)
Accounts payable and accrued liabilities	**277**	962	301
Change in non-cash working capital	**$ (94)**	$ 372	$ 421
Relating to:			
Operating activities	**$ 544**	$ (94)	$ 147
Financing activities	**(678)**	255	337
Investing activities	**40**	211	(63)

b) Other cash flow information:

	2006	2005	2004
Cash taxes paid	**$ 215**	$ 154	$ 213
Cash interest paid	**147**	147	143

Note 9. Bank Operating Loans

At December 31, 2006, the Company had unsecured short-term borrowing lines of credit with banks totalling $220 million (2005 and 2004 – $195 million). As at December 31, 2006, bank operating loans (excluding reclassified outstanding cheques) were nil (2005 – $0.4 million; 2004 – $49 million) and letters of credit under these lines of credit totalled $19 million (2005 – $18 million; 2004 – $23 million). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2006, the weighted average interest rate on short-term borrowings was approximately 5.8% (2005 – 3.9%; 2004 – 3.4%).

Note 10. Accounts Payable and Accrued Liabilities

	2006	2005	2004
Trade payables	**$ 74**	$ 7	$ 51
Accrued liabilities	**1,221**	1,247	760
Dividend payable	**212**	530	280
Commodity contract settlements	**–**	–	50
Stock-based compensation	**234**	130	49
Current income taxes	**615**	164	119
Other	**218**	232	130
	$ 2,574	$ 2,310	$ 1,439

Note 11. Long-term Debt

		Cdn $ Amount			U.S. $ Denominated		
	Maturity	**2006**	2005	2004	**2006**	2005	2004
Long-term debt							
Syndicated credit facility		**$ –**	$ –	$ 70	**$ –**	$ –	$ –
Bilateral credit facilities		**–**	–	40	**–**	–	–
6.85% medium-term notes – Series B	2007	**100**	100	100	**–**	–	–
6.95% medium-term notes – Series E	2009	**200**	200	200	**–**	–	–
6.25% notes	2012	**466**	467	481	**400**	400	400
7.55% debentures	2016	**233**	233	241	**200**	200	200
6.15% notes	2019	**350**	350	361	**300**	300	300
8.90% capital securities	2028	**262**	262	271	**225**	225	225
7.125% notes		**–**	175	181	**–**	150	150
8.45% senior secured bonds		**–**	99	140	**–**	85	117
Private placement notes		**–**	–	18	**–**	–	15
Total long-term debt		**1,611**	1,886	2,103	**$ 1,125**	$ 1,360	$ 1,407
Amount due within one year		**(100)**	(274)	(56)			
		$ 1,511	$ 1,612	$ 2,047			

Interest – net for the years ended December 31 was as follows:

	2006	2005	2004
Long-term debt	$ 130	$ 144	$ 133
Short-term debt	5	4	3
	135	148	136
Amount capitalized	(33)	(114)	(75)
	102	34	61
Interest income	(10)	(2)	(1)
	$ 92	$ 32	$ 60

Foreign exchange for the years ended December 31 was as follows:

	2006	2005	2004
Gain on translation of U.S. dollar denominated long-term debt	$ (7)	$ (51)	$ (150)
Cross currency swaps	4	14	27
Other losses	(21)	6	3
	$ (24)	$ (31)	$ (120)

As at December 31, 2006, other assets included $12 million (2005 – $21 million; 2004 – $24 million) of deferred debt issue costs.

Credit Facilities

The revolving syndicated credit facility allows the Company to borrow up to $1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a five-year committed revolving credit facility. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the syndicated credit facility.

Notes and Debentures

On September 21, 2006, Husky filed a shelf prospectus, which replaces the Company's shelf prospectus dated August 11, 2004, and enables Husky to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the 25-month period that the prospectus remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. As at December 31, 2006, no debt securities were issued under this new shelf prospectus.

The medium-term notes Series B and Series E represent unsecured securities issued under trust indentures dated February 3, 1997 and May 4, 1999, respectively. Interest is payable semi-annually on both series.

The 6.25% and the 6.15% notes represent unsecured securities issued under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

The 7.55% debentures represent unsecured securities issued under a trust indenture dated October 31, 1996 and mature in 2016. Interest is payable semi-annually.

The 8.90% capital securities represent unsecured securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. The 8.90% interest is payable semi-annually until August 15, 2008. The capital securities mature in 2028. They are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate plus an applicable spread. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the interest rate changes to a floating rate equal to U.S. LIBOR plus 5.50% payable semi-annually. The Company has the right at any time prior to maturity, subject to certain conditions, to defer payment of interest for up to five years. The Company also has the unrestricted ability to settle its deferred interest, principal and redemption obligations through the issuance of common or preferred shares.

The 7.125% notes represented unsecured securities issued under a trust indenture dated October 31, 1996 and matured in 2006. Interest was payable semi-annually.

The 8.45% senior secured bonds represented securities issued by a subsidiary under a trust indenture dated July 20, 1999 and were redeemed in full on February 1, 2006. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oil field located off the East Coast of Canada. Interest was payable semi-annually. Certain related financial obligations required collateral of letters of credit and/or cash equivalents. As at December 31, 2005 and 2004, letters of credit totalling $41 million and $54 million, respectively, were outstanding.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread.

Note 12. Other Long-term Liabilities

	2006	2005	2004
Asset retirement obligations	**$ 622**	$ 557	$ 509
Cross currency swaps	**40**	40	68
Interest rate swaps	**37**	42	18
Employee future benefits	**30**	27	23
Stock-based compensation	**4**	46	14
Other	**23**	18	–
	$ 756	$ 730	$ 632

Asset Retirement Obligations

At December 31, 2006, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.8 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2% to 6.5%.

Changes to the asset retirement obligations were as follows:

	2006	2005	2004
Asset retirement obligations at beginning of year	**$ 557**	$ 509	$ 432
Liabilities incurred	**35**	63	13
Liabilities disposed	**(1)**	(7)	–
Liabilities settled	**(36)**	(41)	(40)
Revisions	**22**	–	77
Accretion	**45**	33	27
Asset retirement obligations at end of year	**$ 622**	$ 557	$ 509

Note 13. Income Taxes

The provision for income taxes in the Consolidated Statements of Earnings reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2006	2005	2004
Earnings before income taxes			
Canadian	**$ 3,276**	$ 2,553	$ 1,165
Foreign jurisdictions	**230**	259	240
	3,506	2,812	1,405
Statutory income tax rate *(percent)*	**35.7**	38.4	39.3
Expected income tax	**1,252**	1,080	552
Effect on income tax of:			
Royalties, lease rentals and mineral taxes payable to the crown	**10**	105	153
Resource allowance on Canadian production income	**(35)**	(133)	(156)
Rate benefit on partnership earnings	**(97)**	(69)	(42)
Change in statutory tax rate	**(328)**	(4)	(40)
Non-deductible capital taxes	**(17)**	15	20
Capital gains and losses	**(1)**	(140)	(23)
Foreign jurisdictions	**(6)**	(14)	(13)
Other – net	**2**	(31)	(52)
Income tax expense	**$ 780**	$ 809	$ 399

The future income tax liability at December 31 comprised the tax effect of temporary differences as follows:

	2006	2005	2004
Future tax liabilities			
Property, plant and equipment	**$ 3,607**	$ 3,487	$ 2,949
Foreign exchange gains taxable on realization	**48**	60	56
Other temporary differences	**1**	2	5
	3,656	3,549	3,010
Future tax assets			
Asset retirement obligations	**194**	195	180
Loss carry forwards	**2**	–	11
Provincial royalty rebates	**2**	7	14
Other temporary differences	**86**	77	47
	284	279	252
	$ 3,372	$ 3,270	$ 2,758

Note 14. Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on a two-year rolling average of the differential. During 2006, the Company capitalized $85 million (2005 – $68 million; 2004 – $27 million) of payments under this arrangement.

At December 31, 2006, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2007	2008	2009	2010	2011	After 2011	Total
Operating leases	$ 93	$ 208	$ 286	$ 283	$ 167	$ 96	$ 1,133
Firm transportation agreements	169	122	80	62	46	147	626
Unconditional purchase obligations (1)	2,144	970	938	74	62	13	4,201
Lease rentals and exploration work agreements	148	74	73	108	70	167	640
Engineering and construction commitments	140	–	–	–	–	–	140
	$ 2,694	$ 1,374	$ 1,377	$ 527	$ 345	$ 423	$ 6,740

(1) Approximately 72% of the total unconditional purchase obligations are in respect of processing and refined product purchase contracts.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity. In 2005 a lawsuit was settled with proceeds received and the resulting gain was recognized in earnings and recorded in other – net.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and future income taxes.

Note 15. Share Capital

The Company's authorized share capital is as follows:

Common shares – an unlimited number of no par value.

Preferred shares – an unlimited number of no par value, none outstanding.

Common Shares

Changes to issued share capital were as follows:

	Number of Shares	Amount
December 31, 2003	422,175,742	$ 3,457
Stock-based compensation – adoption	–	23
Options and warrants exercised	1,560,672	26
December 31, 2004	423,736,414	3,506
Options and warrants exercised	388,664	17
December 31, 2005	424,125,078	3,523
Options exercised	143,431	10
December 31, 2006	**424,268,509**	**$ 3,533**

Stock Options

At December 31, 2006, 18.3 million common shares were reserved for issuance under the Company stock option plan. As described in note 3 m), on June 1, 2004, the Company modified its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the average market price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

A downward adjustment of $0.55 was made to the exercise price of all outstanding stock options effective December 1, 2005, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $1.00 per share dividend that was declared in November 2005. In 2004 a similar downward adjustment of $0.48 was made to the exercise price of all outstanding stock options as a result of a special dividend declared in that year.

The following options to purchase common shares have been awarded to directors, officers and certain other employees:

	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
December 31, 2003	4,597	$ 13.88	2	3,564
Granted	8,200	$ 25.10	4	
Exercised for common shares	(1,350)	$ 13.11	1	
Surrendered for cash	(1,269)	$ 13.32	1	
Forfeited	(214)	$ 22.73	4	
December 31, 2004	9,964	$ 22.61	4	1,417
Granted	670	$ 48.14	5	
Exercised for common shares	(359)	$ 15.84	1	
Surrendered for cash	(2,443)	$ 19.05	2	
Forfeited	(547)	$ 24.10	3	
December 31, 2005	7,285	$ 25.81	3	1,533
Granted	902	$ 71.42	4	
Exercised for common shares	(144)	$ 22.31	2	
Surrendered for cash	(1,951)	$ 23.95	2	
Forfeited	(264)	$ 42.82	3	
December 31, 2006	**5,828**	**$ 32.81**	**3**	**2,232**

As at December 31, 2006	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$13.96 – $14.99	64	$ 14.60	1	64	$ 14.60
$15.00 – $22.99	96	$ 19.87	2	96	$ 19.87
$23.00 – $23.99	4,164	$ 23.83	2	1,882	$ 23.83
$24.00 – $39.99	294	$ 32.22	3	95	$ 31.69
$40.00 – $55.99	378	$ 52.17	4	95	$ 52.90
$56.00 – $76.74	832	$ 72.04	4	–	$ –
	5,828	**$ 32.81**	**3**	**2,232**	**$ 24.96**

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. ("Renaissance") replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. As at December 31, 2006 and 2005, there were no Renaissance replacement options or warrants outstanding. During 2005 and 2004, 16,000 and 113,600 warrants were exercised respectively.

Earnings per Common Share

	2006	2005	2004
Net earnings	**$ 2,726**	$ 2,003	$ 1,006
Weighted average number of common shares outstanding			
Basic *(millions)*	**424.2**	424.0	423.4
Effect of dilutive stock options and warrants	**–**	–	0.9
Weighted average number of common shares outstanding			
Diluted *(millions)*	**424.2**	424.0	424.3
Earnings per share			
Basic and diluted	**$ 6.43**	$ 4.72	$ 2.37

Stock-based Compensation

Beginning January 1, 2004, stock-based compensation is being recognized in earnings. This change was adopted retroactively without restatement of prior periods and resulted in a decrease to retained earnings of $44 million, an increase to contributed surplus of $21 million and an increase to share capital of $23 million on January 1, 2004.

Effective June 1, 2004, the Company modified the stock option plan to a tandem plan. Prior to the modification, the fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The grant date fair values and assumptions used prior to June 1, 2004 were:

	2004
Weighted average fair value per option	$ 5.67
Risk-free interest rate *(percent)*	3.1
Volatility *(percent)*	21
Expected life *(years)*	5
Expected annual dividend per share	$ 0.44

Dividends

During 2006, the Company declared dividends of $1.50 per common share (2005 – $1.65 per common share; 2004 – $1.00 per common share), including special dividends of $1.00 per common share in 2005 and $0.54 per common share in 2004.

Contributed Surplus

Changes to contributed surplus were as follows:

	2004
December 31, 2003	$ –
Stock-based compensation – adoption	21
Stock-based compensation cost	1
Stock options exercised	(6)
Modification of stock option plan – June 1, 2004	(16)
December 31, 2004	$ –

Note 16. Employee Future Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain health and dental coverage to its retirees, which is accrued over the expected average remaining service life of the employees.

Defined Benefit Pension Plan

Weighted average long-term assumptions are based on independent historical and projected references and are noted below:

	2006	2005	2004
Discount rate *(percent)*	**5.0**	5.8	6.0
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**7.5**	7.5	8.0

The discount rate used at the end of 2006 to determine the accrued benefit obligation was 5%.

The long-term rate of return on the assets was determined based on management's best estimate and the historical rates of return, adjusted periodically. The rate at the end of 2006 was 7.5%.

The status of the defined benefit pension plan at December 31 was as follows:

Benefit Obligation	**2006**	2005	2004
Benefit obligation, beginning of year	**$ 138**	$ 124	$ 118
Current service cost	**3**	2	2
Interest cost	**7**	7	7
Benefits paid	**(7)**	(6)	(6)
Actuarial losses	**8**	11	3
Benefit obligation, end of year	**$ 149**	$ 138	$ 124

Fair Value of Plan Assets	**2006**	2005	2004
Fair value of plan assets, beginning of year	**$ 108**	$ 96	$ 85
Contributions	**13**	11	10
Benefits paid	**(7)**	(6)	(6)
Expected return on plan assets	**8**	7	7
Gain on plan assets	**10**	–	1
Foreign exchange losses	**–**	–	(1)
Fair value of plan assets, end of year	**$ 132**	$ 108	$ 96

Funded Status of Plan	**2006**	2005	2004
Fair value of plan assets	**$ 132**	$ 108	$ 96
Benefit obligation	**(149)**	(138)	(124)
Excess obligation	**(17)**	(30)	(28)
Unrecognized past service costs	**3**	1	1
Unrecognized losses	**33**	40	32
Accrued benefit asset	**$ 19**	$ 11	$ 5

Husky adheres to a Statement of Investment Policies and Procedures (the "Policy"). The assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The Company's actuaries perform valuations as at December 31 for the defined benefit pension plan. The last actuarial valuation was conducted in 2006 and the next valuation will be conducted in 2007.

The composition of the defined benefit pension plan assets was as follows:

	2006	2005	2004
U.S. common equities	**1%**	–%	15%
Canadian common equities	**30**	29	25
International equity mutual funds	**30**	28	11
Canadian government bonds	**16**	18	25
Canadian corporate bonds	**3**	3	16
Canadian fixed income mutual funds	**19**	20	–
Cash and receivables	**1**	2	8
Total	**100%**	100%	100%

During 2006, Husky contributed $13 million to the defined benefit pension plan assets, $11 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute $13 million in 2007.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10% of the greater of the accrued benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. The gains or losses that are in excess of 10% are amortized over the expected future years of service, which is currently seven years.

The past service costs are amortized over the expected future years of service.

Post-retirement Health and Dental Care Plan

The discount rate used in the calculation of the benefit obligation was 5%. The average health care cost trend used was 9.5% which is reduced by 0.50% until 2015. The average dental care cost trend used was 4%, which remains constant.

The status of the post-retirement health and dental care plan at December 31 was as follows:

Benefit Obligation	2006	2005	2004
Benefit obligation, beginning of year	**$ 33**	$ 25	$ 23
Current service cost	**2**	2	2
Interest cost	**2**	1	1
Benefits paid	**–**	–	(1)
Actuarial losses	**12**	5	–
Benefit obligation, end of year	**$ 49**	$ 33	$ 25

Funded Status of Plan	2006	2005	2004
Benefit obligation	**$ (49)**	$ (33)	$ (25)
Unrecognized losses	**19**	6	2
Accrued benefit liability	**$ (30)**	$ (27)	$ (23)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 1	$ (1)
Effect on post-retirement benefit obligation	$ 11	$ (8)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

Pension Expense	**2006**	2005	2004
Defined benefit pension plan			
Employer current service cost	**$ 3**	$ 2	$ 2
Interest cost	**7**	7	7
Expected return on plan assets	**(8)**	(7)	(7)
Amortization of net actuarial losses	**3**	3	2
	5	5	4
Defined contribution pension plan	**16**	14	12
Total expense	**$ 21**	$ 19	$ 16

Post-retirement Health and Dental Care Expense	**2006**	2005	2004
Employer current service cost	**$ 2**	$ 2	$ 2
Interest cost	**2**	1	1
Total expense	**$ 4**	$ 3	$ 3

Future Benefit Payments

The following table discloses the current estimate of future benefit payments:

	Defined Benefit Pension Plan	Post-retirement Health and Dental Care Plan
2007	$ 8	$ 1
2008	8	1
2009	9	1
2010	10	1
2011	9	1
2012 – 2016	51	9

Note 17. Related Party Transactions

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, Husky paid approximately $10 million for office space in Western Canadian Place during 2004.

Note 18. Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these instruments.

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. The estimated fair value of the long-term debt at December 31 was as follows:

	2006		2005		2004	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**$ 1,611**	**$ 1,671**	$ 1,886	$ 1,995	$ 2,103	$ 2,296

Recognized Gains (Losses) on Derivative Instruments

Recognized gains (losses) for the years ended December 31 were as follows:

	2006	2005	2004
Commodity price risk management			
Power consumption	**$ 6**	$ 4	$ 3
Natural gas	**-**	(17)	(1)
Crude oil	**-**	-	(560)
Interest rate risk management	**1**	13	22
Foreign exchange risk management	**(3)**	1	(13)

Unrecognized Gains (Losses) on Derivative Instruments

	2006	2005	2004
Commodity price risk management			
Power consumption	**$ -**	$ -	$ (1)
Natural gas	**-**	-	(9)
Interest rate risk management			
Interest rate swaps	**5**	7	52
Foreign currency risk management			
Foreign exchange contracts	**(26)**	(32)	(30)

Commodity Price Risk Management

Natural Gas and Crude Oil Production

The Company did not have a natural gas hedge program in 2006 or a crude oil hedge program in 2005 and 2006.

Power Consumption

At December 31, 2006, the Company had hedged power consumption as follows:

	Notional Volumes *(MW)*	Term	Price
Fixed price purchase	20.0	Apr. to Jun. 2007	$63.63/MWh

Natural Gas Contracts

The Company has a portfolio of fixed and basis price offsetting physical forward purchase and sale natural gas contracts relating to marketing of other producers' natural gas. The objective of these contracts is to "lock in" a positive spread between the physical purchase and sale contract prices. At December 31, 2006, the Company had the following offsetting physical purchase and sale contracts:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	25,509	$ 5
Physical sale contracts	(25,509)	$ 1

Interest Rate Risk Management

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2006, the Company had entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps

In 2005 the Company unwound interest rate swaps for proceeds of $37 million. The proceeds have been deferred and are being amortized to income over the remaining term of the underlying debt.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange rate fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2006, the Company had the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*
6.25% notes	U.S. $150	$212	June 15, 2012	7.41
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61

The Company hedged U.S. dollar revenues for various amounts and maturities through 2006 using foreign exchange forwards. On November 10, 2004, the Company unwound its long-dated forwards, which resulted in a gain of $8 million that was deferred and was recognized into income during 2005 on the dates that the underlying hedged transactions took place.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks.

In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its derivative financial instruments. The Company's policy is to primarily deal with major financial institutions and investment grade rated entities to mitigate these risks.

Husky did not have any customers that constituted more than 10% of total sales and operating revenues during 2006.

New CICA Handbook Sections for Financial Instruments

In April 2005, the Accounting Standards Board issued three new CICA Handbook Sections: CICA section 3855, "Financial Instruments – Recognition and Measurement;" CICA section 3865, "Hedges;" and, CICA section 1530, "Comprehensive Income."

Effective January 1, 2007 all financial instruments, including derivatives, must initially be recognized at fair value on the balance sheet. Subsequent measurement and classification of gains or losses related to the financial instrument depend on its classification.

Hedge accounting continues to be optional and the new section gives detailed guidance on the application of hedge accounting and the required disclosures. The current hedging requirements have been expanded and specific guidance has been provided on how to apply hedge accounting, including recognition in the financial statements.

Accumulated other comprehensive income is a new equity category where certain revenues, expenses, gains and losses are temporarily presented outside of net earnings but included in comprehensive income and reclassified to net earnings when required by GAAP. A new financial statement is required entitled the "Statement of Comprehensive Income," which combines net earnings and the changes in other comprehensive income and will have the same prominence as the Company's other financial statements.

Adoption is required prospectively and the following represents the required adoption changes for January 1, 2007:

	December 31, 2006 (As Reported)	Adoption Adjustment	January 1, 2007 (As Restated)
Consolidated Balance Sheets			
Assets			
Accounts receivable	$ 1,284	$ 6	$ 1,290
Prepaid expenses	25	(2)	23
Other assets	44	(7)	37
Liabilities and Shareholders' Equity			
Accounts payable and accrued liabilities	2,574	(5)	2,569
Long-term debt due within one year	100	(2)	98
Long-term debt	1,511	34	1,545
Other long-term liabilities	756	(10)	746
Future income taxes	3,372	(6)	3,366
Retained earnings	6,087	4	6,091
Accumulated other comprehensive income	–	(18)	(18)

Note 19. Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects from those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

Consolidated Statements of Earnings	2006	2005	2004
Net earnings under Canadian GAAP	**$ 2,726**	$ 2,003	$ 1,006
Adjustments:			
Full cost accounting [a]	**64**	66	37
Related income taxes	**(20)**	(23)	(13)
Energy trading contracts [c]	**4**	-	(1)
Related income taxes	**(1)**	-	-
Stock-based compensation [d]	**(10)**	-	2
Related income taxes	**3**	-	-
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	**2,766**	2,046	1,031
Cumulative effect of change in accounting principle, net of tax [d]	**11**	-	-
Net earnings under U.S. GAAP	**$ 2,777**	$ 2,046	$ 1,031
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	**424.2**	424.0	423.4
Diluted	**424.2**	424.0	424.3
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	**$ 6.52**	$ 4.83	$ 2.44
Diluted	**$ 6.52**	$ 4.83	$ 2.43
Earnings per share under U.S. GAAP			
Basic	**$ 6.55**	$ 4.83	$ 2.44
Diluted	**$ 6.55**	$ 4.83	$ 2.43

Condensed Consolidated Balance Sheets	2006		2005		2004	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets (b) (c)	**$ 2,179**	**$ 2,190**	$ 1,535	$ 1,591	$ 772	$ 830
Property, plant and equipment, net (a)	**15,550**	**15,120**	13,959	13,465	12,193	11,633
Other assets (g)	**204**	**185**	222	223	268	269
	$17,933	**$17,495**	$15,716	$15,279	$13,233	$12,732
Current liabilities (b) (c) (g)	**$ 2,674**	**$ 2,696**	$ 2,584	$ 2,685	$ 1,596	$ 1,649
Long-term debt (b)	**1,511**	**1,557**	1,612	1,670	2,047	2,124
Other long-term liabilities (b) (g)	**756**	**749**	730	688	632	614
Future income taxes (a) (b) (c) (g)	**3,372**	**3,210**	3,270	3,089	2,758	2,555
Share capital (d) (e) (f)	**3,533**	**3,767**	3,523	3,757	3,506	3,740
Retained earnings	**6,087**	**5,572**	3,997	3,431	2,694	2,085
Accumulated other comprehensive income						
Cash flow hedges, net of tax (b)	**–**	**(18)**	–	(21)	–	(20)
Minimum pension liability, net of tax (g)	**–**	**–**	–	(20)	–	(15)
Pension accounting – adoption of FAS 158 (g)	**–**	**(38)**	–	–	–	–
	$17,933	**$17,495**	$15,716	$15,279	$13,233	$12,732

Condensed Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income	2006		2005		2004	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings, beginning of year	**$ 3,997**	**$ 3,431**	$ 2,694	$ 2,085	$ 2,156	$ 1,478
Net earnings	**2,726**	**2,777**	2,003	2,046	1,006	1,031
Dividends on common shares	**(636)**	**(636)**	(700)	(700)	(424)	(424)
Stock-based compensation – retroactive adoption (d)	**–**	**–**	–	–	(44)	–
Retained earnings, end of year	**$ 6,087**	**$ 5,572**	$ 3,997	$ 3,431	$ 2,694	$ 2,085
Accumulated other comprehensive income, beginning of year	**$ –**	**$ (41)**	$ –	$ (35)	$ –	$ (91)
Cash flow hedges, net of tax (b)	**–**	**3**	–	(1)	–	56
Minimum pension liability, net of tax (g)	**–**	**(5)**	–	(5)	–	–
Reversal of minimum pension liability, net of tax – adoption of FAS 158 (g)	**–**	**25**	–	–	–	–
Pension accounting – adoption of FAS 158 (g)	**–**	**(38)**	–	–	–	–
Accumulated other comprehensive income, end of year	**$ –**	**$ (56)**	$ –	$ (41)	$ –	$ (35)

Condensed Consolidated Statements of Earnings and Comprehensive Income	2006		2005		2004	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues [(b) (c)]	**$12,664**	**$10,790**	$10,245	$ 8,445	$ 8,440	$ 7,038
Costs and expenses (excluding depletion, depreciation and amortization) [(b) (c) (d)]	**7,422**	**5,554**	6,112	4,312	5,769	4,366
Accretion expense	**45**	**45**	33	33	27	27
Depletion, depreciation and amortization [(a)]	**1,599**	**1,535**	1,256	1,190	1,179	1,142
Interest – net	**92**	**92**	32	32	60	60
Earnings before income taxes	**3,506**	**3,564**	2,812	2,878	1,405	1,443
Income taxes [(a) (b) (c)]	**780**	**798**	809	832	399	412
Earnings before cumulative effect of change in accounting principle	**2,726**	**2,766**	2,003	2,046	1,006	1,031
Cumulative effect of change in accounting principle, net of tax [(d)]	**–**	**11**	–	–	–	–
Net earnings	**2,726**	**2,777**	2,003	2,046	1,006	1,031
Other comprehensive income [(b) (g)]	**–**	**2**	–	6	–	(56)
Comprehensive income	**$ 2,726**	**$ 2,779**	$ 2,003	$ 2,052	$ 1,006	$ 975

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) Under Canadian GAAP the ceiling test is performed by comparing the carrying value of the cost centre based on the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach of proved plus probable reserves using future prices. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount factor of 10%. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. At December 31, 2001, the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax. Depletion expense for U.S. GAAP is reduced by $60 million (2005 – $62 million; 2004 – $76 million), before tax of $19 million (2005 – $21 million; 2004 – $27 million).

Under U.S. GAAP, prices used in the reserve determination were those in effect at the applicable year-end. For Canadian GAAP, forecast prices are used in the reserve determination. The different prices result in a lower reserve base for U.S. GAAP. Additional depletion of $39 million, net of tax of $14 million, was recorded under U.S. GAAP in December 2004. As of the first quarter of 2005 these reserves have become economical again. Depletion expense for U.S. GAAP is reduced by $4 million (2005 – $4 million), before tax of $1 million (2005 – $2 million).

(b) The Company records all derivative instruments as assets and liabilities on the balance sheet based on their fair values as required under Statement of Financial Accounting Standards ("FAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." At December 31, 2006, the Company recorded additional assets and liabilities for U.S. GAAP purposes of $5 million (2005 – $7 million; 2004 – $52 million) and $31 million (2005 – $39 million; 2004 – $93 million), respectively, for the fair values of derivative financial instruments. The Company also recorded a gain of nil, net of tax (2005 – gain of less than $1 million; 2004 – loss of less than $1 million), in revenue for U.S. GAAP purposes with respect to derivatives designated as fair value hedges relating to commodity price risk. In addition, the amount included in other comprehensive income was decreased by $3 million net of tax (2005 – increased by $1 million; 2004 – decreased by $51 million), for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk, foreign exchange risk and the transfer to income of amounts applicable to cash flows occurring in 2006. In 2004, the Company unwound its long-dated foreign exchange forwards. The unrealized gain of $5 million, before tax was deferred in other comprehensive income and recognized in 2005 when the underlying transactions took place. In 2005 and 2003 the Company unwound interest rate swaps that were fair value hedges of debt for proceeds of $37 million and $44 million, respectively. Under Canadian GAAP, the proceeds received have been recorded to current and long-term liabilities and are being deferred over the life of the debt. For U.S. GAAP purposes, the balance in the current and long-term liabilities has been reclassified to long-term debt consistent with fair value hedge treatment.

(c) Under U.S. GAAP, natural gas purchase and sale contracts related to energy trading activities are recorded at fair value in accordance with Emerging Issues Task Force ("EITF") 02-03, "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, at December 31, 2006, the Company recorded additional assets and liabilities of $6 million (2005 – $49 million; 2004 – $4 million) and nil (2005 – $48 million; 2004 – $3 million), respectively, and included the resulting unrealized gain, net of tax of $3 million (2005 – gain of less than $1 million; 2004 – loss of $1 million), in earnings for the year. Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) Effective January 1, 2004, under Canadian GAAP, the Company adopted fair value accounting for stock-based compensation retroactively without restatement, which is consistent with the recommendations in FAS 123, "Accounting for Stock-based Compensation – Transition and Disclosure."

In January 2006, the Company adopted the fair value accounting provisions under FAS 123(R), "Share-Based Payment." Under FAS 123(R) awards that are classified as liabilities are re-measured based on the award's fair value at each reporting date until settlement. Under FAS 123 awards classified as liabilities were measured at their intrinsic value. FAS 123(R) was adopted using the modified prospective application method. The related cumulative effect of the change in accounting principle to net earnings at December 31, 2005 was an increase of $16 million, before tax of $5 million. The change resulted in a decrease to current liabilities of $12 million and long-term liabilities of $4 million and an increase to future income tax liability of $5 million. There was no impact on the Company's cash flow as a result of adoption of FAS 123(R).

At December 31, 2006, for U.S. GAAP purposes the Company recorded a decrease to current liabilities of $7 million and an increase to long-term liabilities of $1 million. The Company also recorded an increase to net earnings of $6 million, before tax of $2 million.

Under FAS 123(R), the Company is using the Black-Scholes option pricing model to estimate the fair value of the liability related to the options issued under the Company's tandem plan. The assumptions used in calculating fair value were:

	2006
Initial expected life *(years)*	3.5
Expected annual dividend per share	$ 2.00

At December 31, 2006, the total intrinsic value of options exercised during the year was $7 million, the share-based liability paid for the year was $97 million and the total fair value of options vested during the year was $87 million.

The weighted average remaining contractual term of options fully vested and currently exercisable is 2.4 years. The aggregate intrinsic value of options fully vested and currently exercisable is $120 million and the aggregate intrinsic value of options fully vested and expected to vest is $267 million. The unrecognized compensation cost for 2006 related to non-vested awards is $30 million and the weighted average period that these costs will be recognized over is 0.9 years.

(e) As a result of the reorganization of the capital structure which occurred in 2000, the deficit of Husky Oil Limited of $160 million was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(f) Until 1997 the Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(g) Under FAS 87, "Employers' Accounting for Pensions," the Company amortized the portion of the unrecognized gains or losses that exceeded 10% of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets or a calculated value that recognizes changes in fair value over not more than five years. An additional minimum liability was recognized if the unfunded accumulated benefit obligation exceeded the unfunded pension cost already recognized. If an additional minimum liability was recognized, an amount equal to the unrecognized prior service cost was recognized as an intangible asset and any excess was reported in other comprehensive income.

At December 31, 2006, the additional minimum liability was increased by $6 million (2005 – increase of $6 million; 2004 – decrease of $1 million) with a decrease to other comprehensive income of $5 million (2005 – decrease of $5 million; 2004 – decrease of less than $1 million), net of tax.

In December 2006, the Company adopted FAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." This standard requires the Company to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability. The funded status is measured as the difference between the fair value of a plan's assets and its benefit obligations. Changes in this funded status are recognized through comprehensive income in the year in which the change occurs. The additional minimum liability previously recorded under FAS 87 has been eliminated. There is no impact to earnings recognition under the new requirement.

The following is the impact of initially applying FAS 158:

	Before FAS 158 Adoption	Adoption Adjustment	After FAS 158 Adoption
Consolidated Balance Sheets			
Assets			
Other assets – prepaid pension asset	$ 19	$ (19)	$ –
Liabilities and Shareholders' Equity			
Additional minimum liability	36	(36)	–
Long-term liability – pension payable	30	(30)	–
Current liability – unfunded status of plan	–	8	8
Long-term liability – unfunded status of plan	–	58	58
Future income taxes	3,216	(6)	3,210
Accumulated other comprehensive income	(43)	(13)	(56)

The amounts reported in accumulated other comprehensive income at December 31, 2006 are comprised of experience gains and losses from prior periods and $5 million is expected to be recognized as a component of net periodic benefit cost over the next year. The Company does not expect to return any of the plan assets to the Company within the next year.

Additional U.S. GAAP Disclosures

Corporate Acquisitions

As described in note 7, Corporate Acquisition, the Company purchased all of the outstanding shares of Temple Exploration Inc. This transaction increased the reserve base and created cost efficiencies, increasing shareholder value.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, the portion of the changes in the fair value of the derivatives that are effective in hedging the changes in future cash flows are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

Stock Option Plan

In December 2004, the Financial Accounting Standards Board ("FASB") issued FAS 123(R), which replaces FAS 123 and supersedes Accounting Principles Board ("APB") Opinion 25. FAS 123(R) requires compensation cost related to share-based payments be recognized in the financial statements and that the cost must be measured based on the fair value of the equity or liability instruments issued. Under FAS 123(R) all share-based payment plans must be valued using option-pricing models. For U.S. GAAP, the liability related to the options issued under the Company's tandem plan is measured at fair value using an option pricing model. Under Canadian GAAP, the liability is measured based on the intrinsic value of the option. Over the life of the option the amount of compensation expense recognized will differ under U.S. and Canadian GAAP, creating a temporary GAAP timing difference. At exercise or surrender of the option, the compensation expense to be recorded will be equal to the cash payment, which will be identical under U.S. and Canadian GAAP and there will no longer be a GAAP difference. FAS 123(R) was effective January 1, 2006.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent ("boe") using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2006	2005	2004
Depletion, depreciation and amortization per boe	**$ 10.75**	$ 9.38	$ 8.76

Accounting for Inventory Costs

In November 2004, the FASB issued FAS 151, "Inventory Costs," which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current period expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities. FAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The application of FAS 151 did not have an impact on the financial statements.

Accounting for Exchanges of Nonmonetary Assets

In December 2004, the FASB issued FAS 153, "Exchanges of Nonmonetary Assets," which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged.

FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The adoption of FAS 153 did not have an impact on the financial statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued FAS 154, "Accounting Changes and Error Corrections," which deals with all voluntary changes in accounting principles and changes required by an accounting pronouncement if that pronouncement does not include specific transition provisions. FAS 154 replaces APB Opinion 20, "Accounting Changes" and FAS 3, "Reporting Accounting Changes in Interim Financial Statements." This Statement requires retrospective application of a change in accounting principle to prior periods' financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change, in which case the change in principle is applied as if it were adopted prospectively from the earliest date practicable. Corrections of an error require adjusting previously issued financial statements. FAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005.

Accounting for Certain Hybrid Financial Instruments

In February 2006, the FASB issued FAS 155, "Accounting for Certain Hybrid Financial Instruments – an Amendment of FASB Statements No. 133 and 140," which addresses a temporary exemption from the application of the bifurcation requirements of FAS 133 to beneficial interests in securitized financial assets. Under the new standard, a requirement exists to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative which requires bifurcation. FAS 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative and would otherwise require bifurcation from the host contract. This standard eliminates the exemption from applying FAS 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. FAS 155 also eliminates the exclusion of a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. FAS 155 is effective for all financial instruments acquired or issued in fiscal years beginning after September 15, 2006. The Company does not have any material hybrid financial instruments.

Accounting for Servicing of Financial Assets

In March 2006, the FASB issued FAS 156, "Accounting for Servicing of Financial Assets – an Amendment of FASB Statement No. 140." This Statement requires an entity to recognize a servicing asset or servicing liability each time it undergoes an obligation to service a financial asset by entering into certain servicing contracts. All separately recognized servicing assets and servicing liabilities are initially measured at fair value. For subsequent measurement of servicing assets and servicing liabilities, an entity is permitted to choose between the amortization method and the fair value measurement method. FAS 156 requires separate presentation of servicing assets and servicing liabilities subsequently measured in the balance sheet. Additional disclosures are required for separately recognized servicing assets and servicing liabilities. FAS 156 is effective for the first fiscal year beginning after September 15, 2006. The Company does not believe that the application of FAS 156 will have a material impact on the financial statements.

Fair Value Measurement

In September 2006, the FASB issued FAS 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in U.S. GAAP pronouncements and expands the disclosure requirements for fair value measurements. Prior to FAS 157, various definitions of fair value existed with limited guidance for application of these definitions in U.S. GAAP. Fair value under this standard is focused on a market-based measurement as opposed to an entity-specific measurement. This standard establishes a fair value hierarchy which distinguishes between market participant assumptions based on market data obtained from independent sources and the reporting entity's own assumptions about the market. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The provisions of this Statement are applied prospectively with certain exceptions which require retrospective application. The Company will consider this fair value measurement framework when applying other U.S. GAAP pronouncements where fair value is a consideration.

Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued FASB Interpretation No. ("FIN") 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." This interpretation clarifies the accounting for the uncertainty in income taxes recognized in accordance with FAS 109. FIN 48 establishes a two-step process for the evaluation of a tax position taken or expected to be taken in a tax return. The first step recognizes whether or not a tax position is sustainable based on a "more-likely-than-not" determination. The second step measures the amount of tax benefit to recognize in the financial statements if the tax position meets the more-likely-than-not threshold. Under FIN 48, the tax position is measured as the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company is currently determining the impact of this issue.

Accounting for Purchases and Sales of Inventory with the Same Counterparty

In September 2005, the EITF redeliberated EITF 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." In arrangements whereby one inventory transaction is legally contingent upon the performance of another inventory transaction with the same counterparty, these transactions are considered a single exchange transaction subject to APB Opinion No. 29. EITF 04-13 clarifies that nonmonetary exchanges whereby an entity transfers finished goods inventory in exchange for the receipt of raw materials or work-in-progress inventory within the same line of business is not an exchange transaction to facilitate sales to customers. These nonmonetary exchanges are required to be recognized at fair value if reasonably determinable and the transaction has commercial substance. All other nonmonetary exchanges of inventory within the same line of business are to be recognized at the carrying amount of the inventory transferred. EITF 04-13 is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first interim or annual reporting period beginning after March 15, 2006. The application of EITF 04-13 did not have a material impact on the financial statements.

Quantifying Financial Statement Misstatements

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin ("SAB") 108 on quantifying financial statement misstatements. This guidance outlines the approach that the SEC believes registrants should use in quantifying and evaluating misstatements of financial statements. SAB 108 requires registrants to adjust their financial statements if the misstatement quantified under the new approach, including prior-year effects, results in a material error in the current year. This adjustment is required even if misstatements of prior years are considered immaterial. If registrants followed an acceptable approach to quantifying financial statement misstatements in the past, the SEC will not require these registrants to restate prior years' historical financial statements. Instead, these registrants will be able to report the cumulative effect of adopting the new approach as an adjustment to the current year's beginning retained earnings balance. If entities correct prior-year financial statements for immaterial errors, this guidance does not require amendments to previously filed reports. Instead, this correction can be made the next time the entity files the prior year financial statements. SAB 108 is effective for fiscal years ending after November 15, 2006. The application of SAB 108 did not have an impact on the financial statements.

Supplemental Financial and Operating Information

Quarterly Financial and Operating Information

Segmented Operational Information

		2006				2005			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream									
Daily production, before royalties									
Light crude oil & NGL *(mbbls/day)*		128.2	117.2	97.7	100.5	75.4	56.4	62.5	64.1
Medium crude oil *(mbbls/day)*		28.0	28.1	28.5	29.4	31.0	30.3	30.6	32.4
Heavy crude oil *(mbbls/day)*		109.4	107.9	105.6	109.5	109.5	103.3	100.9	110.4
Bitumen *(mbbls/day)*		0.1	-	-	-	-	-	-	-
		265.7	253.2	231.8	239.4	215.9	190.0	194.0	206.9
Natural gas *(mmcf/day)*		662.2	669.1	672.8	685.4	675.3	679.2	689.3	676.2
Total production *(mboe/day)*		376.1	364.7	344.0	353.6	328.5	303.2	308.9	319.6
Average sales prices									
Light crude oil & NGL *($/bbl)*		$ 62.55	$ 74.05	$ 73.74	$ 67.04	$ 63.20	$ 67.21	$ 59.51	$ 56.43
Medium crude oil *($/bbl)*		$ 43.99	$ 57.35	$ 58.42	$ 38.39	$ 43.60	$ 53.41	$ 40.45	$ 36.50
Heavy crude oil *($/bbl)*		$ 35.46	$ 49.62	$ 48.12	$ 26.73	$ 29.98	$ 44.17	$ 27.95	$ 22.53
Natural gas *($/mcf)*		$ 6.19	$ 5.69	$ 5.95	$ 8.06	$ 11.39	$ 7.86	$ 6.76	$ 6.07
Operating costs *($/boe)*		$ 9.51	$ 8.45	$ 8.24	$ 8.78	$ 8.90	$ 8.18	$ 7.74	$ 7.60
Operating netbacks (1)									
Light crude oil *($/boe)* (2)		$ 51.66	$ 61.86	$ 60.40	$ 54.97	$ 48.32	$ 51.78	$ 47.20	$ 44.03
Medium crude oil *($/boe)* (2)		$ 21.02	$ 33.34	$ 35.06	$ 19.72	$ 24.80	$ 32.00	$ 23.58	$ 19.48
Heavy crude oil *($/boe)* (2)		$ 18.94	$ 32.01	$ 31.30	$ 12.65	$ 15.73	$ 28.06	$ 15.52	$ 11.27
Natural gas *($/mcfge)* (3)		$ 3.73	$ 3.55	$ 3.98	$ 5.16	$ 7.76	$ 4.95	$ 4.30	$ 3.83
Total *($/boe)* (2)		$ 31.00	$ 38.46	$ 37.34	$ 30.89	$ 34.42	$ 33.48	$ 26.24	$ 22.80
Net wells drilled (4)									
Exploration	Oil	29	40	8	22	25	28	10	22
	Gas	42	50	16	84	60	43	21	72
	Dry	2	5	2	15	10	7	5	14
		73	95	26	121	95	78	36	108
Development	Oil	209	163	59	112	167	147	58	61
	Gas	159	115	22	194	150	136	44	221
	Dry	5	6	2	9	16	8	5	10
		373	284	83	315	333	291	107	292
		446	379	109	436	428	369	143	400
Success ratio *(percent)*		98	97	96	94	94	96	93	94
Midstream									
Synthetic crude oil sales *(mbbls/day)*		64.1	65.7	56.9	63.4	62.2	43.9	60.1	63.9
Upgrading differential *($/bbl)*		$ 23.81	$ 23.75	$ 22.73	$ 34.82	$ 33.31	$ 23.53	$ 31.05	$ 32.09
Pipeline throughput *(mbbls/day)*		465	457	480	500	480	418	488	510
Refined Products									
Refined products sales volumes									
Light oil products *(million litres/day)*		8.6	9.1	8.6	8.6	9.0	9.3	8.8	8.3
Asphalt products *(mbbls/day)*		21.0	30.0	24.9	17.7	22.4	29.9	19.7	17.7
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		28.1	27.9	25.4	27.1	27.4	25.9	21.6	27.1
Prince George refinery *(mbbls/day)*		11.2	11.6	3.7	9.3	9.7	9.6	9.5	10.0
Refinery utilization *(percent)*		98	99	73	91	106	101	89	106

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.

(2) Includes associated co-products converted to boe.

(3) Includes associated co-products converted to mcfge.

(4) Western Canada.

Segmented Financial Information

	Upstream				Midstream			
					Upgrading			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2006								
Sales and operating revenues, net of royalties	$ 1,434	$ 1,600	$ 1,451	$ 1,287	$ 385	$ 485	$ 404	$ 405
Costs and expenses								
Operating, cost of sales, selling and general	373	329	308	311	293	399	319	262
Depletion, depreciation and amortization	389	382	354	351	6	6	6	6
Interest – net	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-
	762	711	662	662	299	405	325	268
Earnings (loss) before income taxes	672	889	789	625	86	80	79	137
Current income taxes	62	158	156	143	(31)	31	29	24
Future income taxes	157	123	(189)	70	58	(5)	(29)	20
Net earnings (loss)	$ 453	$ 608	$ 822	$ 412	$ 59	$ 54	$ 79	$ 93
Capital employed	$ 9,482	$ 9,264	$ 9,440	$ 8,977	$ 553	$ 503	$ 539	$ 547
Capital expenditures (2)	$ 704	$ 612	$ 554	$ 757	$ 65	$ 44	$ 38	$ 37
Total assets (3)	$ 13,920	$ 13,531	$ 13,443	$ 13,237	$ 992	$ 943	$ 912	$ 858
2005								
Sales and operating revenues, net of royalties	$ 1,327	$ 1,176	$ 976	$ 888	$ 414	$ 328	$ 393	$ 353
Costs and expenses								
Operating, cost of sales, selling and general	299	262	249	240	291	283	249	195
Depletion, depreciation and amortization	313	280	278	273	6	6	4	5
Interest – net	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-
	612	542	527	513	297	289	253	200
Earnings (loss) before income taxes	715	634	449	375	117	39	140	153
Current income taxes	46	47	69	53	3	4	(2)	11
Future income taxes	136	142	73	83	32	8	45	35
Net earnings (loss)	$ 533	$ 445	$ 307	$ 239	$ 82	$ 27	$ 97	$ 107
Capital employed	$ 8,741	$ 8,037	$ 7,916	$ 7,668	$ 510	$ 489	$ 491	$ 510
Capital expenditures (2)	$ 831	$ 701	$ 536	$ 662	$ 35	$ 38	$ 30	$ 17
Total assets (3)	$ 12,887	$ 11,920	$ 11,575	$ 11,286	$ 844	$ 806	$ 751	$ 714

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) Excludes capitalized costs related to asset retirement obligations incurred during the period.

(3) Includes goodwill on corporate acquisitions related to Upstream.

	Midstream Infrastructure and Marketing				Refined Products				Corporate and Eliminations (1)				Total			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
	$ 2,377	$ 2,451	$ 2,267	$ 2,464	$ 579	$ 776	$ 674	$ 546	$ (1,691)	$ (1,876)	$ (1,756)	$ (1,598)	$ 3,084	$ 3,436	$ 3,040	$ 3,104
	2,300	2,396	2,190	2,372	550	724	596	511	(1,671)	(1,837)	(1,705)	(1,529)	1,845	2,011	1,708	1,927
	7	6	5	6	14	11	13	10	10	6	5	6	426	411	383	379
	-	-	-	-	-	-	-	-	24	19	22	27	24	19	22	27
	-	-	-	-	-	-	-	-	8	5	(32)	(5)	8	5	(32)	(5)
	2,307	2,402	2,195	2,378	564	735	609	521	(1,629)	(1,807)	(1,710)	(1,501)	2,303	2,446	2,081	2,328
	70	49	72	86	15	41	65	25	(62)	(69)	(46)	(97)	781	990	959	776
	22	18	20	19	2	5	3	9	(1)	(2)	2	9	54	210	210	204
	2	(2)	(9)	10	3	8	10	-	(35)	(26)	(12)	(52)	185	98	(229)	48
	$ 46	$ 33	$ 61	$ 57	$ 10	$ 28	$ 52	$ 16	$ (26)	$ (41)	$ (36)	$ (54)	$ 542	$ 682	$ 978	$ 524
	$ 843	$ 601	$ 339	$ 303	$ 561	$ 711	$ 585	$ 527	$ (208)	$ (68)	$ (367)	$ (443)	$ 11,231	$ 11,011	$ 10,536	$ 9,911
	$ 27	$ 29	$ 11	$ 1	$ 83	$ 59	$ 79	$ 64	$ 14	$ 10	$ 7	$ 6	$ 893	$ 754	$ 689	$ 865
	$ 1,329	$ 1,093	$ 718	$ 763	$ 1,114	$ 1,070	$ 998	$ 883	$ 578	$ 687	$ 257	$ 114	$ 17,933	$ 17,324	$ 16,328	$ 15,855

	$ 2,512	$ 1,808	$ 1,611	$ 1,452	$ 632	$ 716	$ 560	$ 437	$ (1,678)	$ (1,434)	$ (1,190)	$ (1,036)	$ 3,207	$ 2,594	$ 2,350	$ 2,094
	2,427	1,752	1,552	1,353	592	660	518	399	(1,681)	(1,363)	(1,118)	(983)	1,928	1,594	1,450	1,204
	5	5	6	5	13	14	11	9	6	6	5	6	343	311	304	298
	-	-	-	-	-	-	-	-	16	-	6	10	16	-	6	10
	-	-	-	-	-	-	-	-	5	(63)	20	7	5	(63)	20	7
	2,432	1,757	1,558	1,358	605	674	529	408	(1,654)	(1,420)	(1,087)	(960)	2,292	1,842	1,780	1,519
	80	51	53	94	27	42	31	29	(24)	(14)	(103)	(76)	915	752	570	575
	-	(3)	(4)	(7)	-	(1)	(1)	(1)	28	31	13	11	77	78	75	67
	27	20	24	39	10	16	12	12	(36)	(68)	(53)	(45)	169	118	101	124
	$ 53	$ 34	$ 33	$ 62	$ 17	$ 27	$ 20	$ 18	$ (16)	$ 23	$ (63)	$ (42)	$ 669	$ 556	$ 394	$ 384
	$ 390	$ 697	$ 596	$ 625	$ 481	$ 408	$ 406	$ 376	$ (716)	$ (332)	$ (237)	$ (220)	$ 9,406	$ 9,299	$ 9,172	$ 8,959
	$ 13	$ 11	$ 7	$ 6	$ 86	$ 57	$ 43	$ 5	$ 7	$ 6	$ 4	$ 4	$ 972	$ 813	$ 620	$ 694
	$ 866	$ 1,042	$ 871	$ 925	$ 834	$ 783	$ 727	$ 647	$ 285	$ 119	$ 131	$ 109	$ 15,716	$ 14,670	$ 14,055	$ 13,681

Segmented Financial Information

($ millions)	2006 Q4	2006 Q3	2006 Q2	2006 Q1	2005 Q4	2005 Q3	2005 Q2	2005 Q1
Capital Expenditures (1)								
Upstream								
Western Canada	**$ 630**	**$ 465**	**$ 397**	**$ 680**	$ 648	$ 451	$ 376	$ 532
East Coast Canada and Frontier	**66**	**104**	**115**	**73**	151	230	140	124
International	**8**	**43**	**42**	**4**	32	20	20	6
	704	**612**	**554**	**757**	831	701	536	662
Midstream								
Upgrader	**65**	**44**	**38**	**37**	35	38	30	17
Infrastructure and Marketing	**27**	**29**	**11**	**1**	13	11	7	6
	92	**73**	**49**	**38**	48	49	37	23
Refined Products	**83**	**59**	**79**	**64**	86	57	43	5
Corporate	**14**	**10**	**7**	**6**	7	6	4	4
	$ 893	**$ 754**	**$ 689**	**$ 865**	$ 972	$ 813	$ 620	$ 694

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period.

Five-year Financial and Operating Information

Segmented Financial Information

	Upstream					Midstream									
						Upgrading					Infrastructure and Marketing				
($ millions)	**2006**	2005	2004	2003	2002	**2006**	2005	2004	2003	2002	**2006**	2005	2004	2003	2002
Year ended December 31															
Sales and operating revenues, net of royalties	**$ 5,772**	$ 4,367	$ 3,120	$3,186	$2,665	**$1,679**	$ 1,488	$ 1,058	$1,013	$ 909	**$9,559**	$ 7,383	$ 6,126	$ 4,946	$ 4,230
Costs and expenses															
Operating, cost of sales, selling and general	**1,321**	1,050	967	873	743	**1,273**	1,018	884	901	811	**9,258**	7,084	5,914	4,747	4,038
Depletion, depreciation and amortization	**1,476**	1,144	1,077	918	822	**24**	21	19	20	18	**24**	21	21	21	20
Interest – net	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
Foreign exchange	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
	2,797	2,194	2,044	1,791	1,565	**1,297**	1,039	903	921	829	**9,282**	7,105	5,935	4,768	4,058
Earnings (loss) before income taxes	**2,975**	2,173	1,076	1,395	1,100	**382**	449	155	92	80	**277**	278	191	178	172
Current income taxes	**519**	215	211	95	55	**53**	16	–	1	1	**79**	(14)	31	27	6
Future income taxes	**161**	434	152	233	346	**44**	120	43	20	25	**1**	110	32	37	59
Net earnings (loss)	**$ 2,295**	$ 1,524	$ 713	$1,067	$ 699	**$ 285**	$ 313	$ 112	$ 71	$ 54	**$ 197**	$ 182	$ 128	$ 114	$ 107
Capital employed – As at December 31	**$ 9,482**	$ 8,741	$ 7,628	$6,627	$6,120	**$ 553**	$ 510	$ 481	$ 456	$ 320	**$ 843**	$ 390	$ 426	$ 465	$ 458
Total assets – As at December 31 (2)	**$13,920**	$12,887	$11,025	$9,847	$8,272	**$ 992**	$ 844	$ 708	$ 650	$ 659	**$1,329**	$ 866	$ 746	$ 804	$ 851

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) Includes goodwill on corporate acquisitions related to Upstream.

Segmented Financial Information

($ millions)	2006	2005	2004	2003	2002
Capital Expenditures [1]					
Upstream					
Western Canada	$ 2,172	$ 2,007	$ 1,533	$ 1,195	$ 1,043
East Coast Canada and Frontier	358	645	539	557	458
International	97	78	85	26	75
	2,627	2,730	2,157	1,778	1,576
Midstream					
Upgrader	184	120	62	25	41
Infrastructure and Marketing	68	37	31	18	23
	252	157	93	43	64
Refined Products	285	191	106	58	44
Corporate	37	21	23	23	23
	$ 3,201	$ 3,099	$ 2,379	$ 1,902	$ 1,707

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Segmented Financial Information (continued)

	Refined Products					Corporate and Eliminations [1]					Total				
($ millions)	2006	2005	2004	2003	2002	2006	2005	2004	2003	2002	2006	2005	2004	2003	2002
Year ended December 31															
Sales and operating revenues, net of royalties	$2,575	$2,345	$1,797	$1,502	$1,310	$(6,921)	$(5,338)	$(3,661)	$(2,989)	$(2,730)	$12,664	$10,245	$ 8,440	$ 7,658	$ 6,384
Costs and expenses															
Operating, cost of sales, selling and general	2,381	2,169	1,694	1,426	1,224	(6,742)	(5,145)	(3,543)	(2,978)	(2,695)	7,491	6,176	5,916	4,969	4,121
Depletion, depreciation and amortization	48	47	38	26	31	27	23	24	36	17	1,599	1,256	1,179	1,021	908
Interest – net	-	-	-	-	-	92	32	60	102	136	92	32	60	102	136
Foreign exchange	-	-	-	-	-	(24)	(31)	(120)	(282)	10	(24)	(31)	(120)	(282)	10
	2,429	2,216	1,732	1,452	1,255	(6,647)	(5,121)	(3,579)	(3,122)	(2,532)	9,158	7,433	7,035	5,810	5,175
Earnings (loss) before income taxes	146	129	65	50	55	(274)	(217)	(82)	133	(198)	3,506	2,812	1,405	1,848	1,209
Current income taxes	19	(3)	11	9	4	8	83	49	15	-	678	297	302	147	66
Future income taxes	21	50	13	9	18	(125)	(202)	(143)	32	(101)	102	512	97	331	347
Net earnings (loss)	$ 106	$ 82	$ 41	$ 32	$ 33	$ (157)	$ (98)	$ 12	$ 86	$ (97)	$ 2,726	$ 2,003	$ 1,006	$ 1,370	$ 796
Capital employed – As at December 31	$ 561	$ 481	$ 360	$ 317	$ 319	$ (208)	$ (716)	$ (491)	$ (158)	$ 295	$11,231	$ 9,406	$ 8,404	$ 7,707	$ 7,512
Total assets – As at December 31	$1,114	$ 834	$ 625	$ 540	$ 537	$ 578	$ 285	$ 129	$ 105	$ 264	$17,933	$15,716	$13,233	$11,946	$10,583

Upstream Operating Information

		2006		2005		2004		2003		2002
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*		**111.0**		64.6		66.2		71.6		65.4
Medium crude oil *(mbbls/day)*		**28.5**		31.1		35.0		39.2		44.8
Heavy crude oil & bitumen *(mbbls/day)*		**108.1**		106.0		108.9		99.9		95.1
		247.6		201.7		210.1		210.7		205.3
Natural gas *(mmcf/day)*		**672.3**		680.0		689.2		610.6		569.2
Total production *(mboe/day)*		**359.7**		315.0		325.0		312.5		300.2
Average sales prices										
Light crude oil & NGL *($/bbl)*	**$**	**69.06**	$	61.56	$	48.34	$	39.53	$	36.17
Medium crude oil *($/bbl)*	**$**	**49.48**	$	43.44	$	36.13	$	31.42	$	30.16
Heavy crude oil *($/bbl)*	**$**	**39.92**	$	31.09	$	28.66	$	25.87	$	26.60
Natural gas *($/mcf)*	**$**	**6.47**	$	7.96	$	6.25	$	5.86	$	3.83
Operating costs *($/boe)*	**$**	**8.77**	$	8.12	$	7.32	$	6.92	$	6.24
Operating netbacks (1)										
Light crude oil *($/boe)* (2)	**$**	**57.06**	$	47.76	$	35.42	$	30.21	$	25.64
Medium crude oil *($/boe)* (2)	**$**	**27.27**	$	24.93	$	20.03	$	16.76	$	17.14
Heavy crude oil *($/boe)* (2)	**$**	**23.65**	$	17.57	$	16.02	$	14.13	$	15.85
Natural gas *($/mcfge)* (3)	**$**	**4.10**	$	5.22	$	3.92	$	3.71	$	2.46

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.
(2) Includes associated co-products converted to boe.
(3) Includes associated co-products converted to mcfge.

Upstream Operating Information

		2006		2005		2004		2003		2002	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled (1) (2) (3)											
Exploration	Oil	**101**	**99**	89	85	45	39	12	11	21	20
	Gas	**330**	**192**	392	196	234	180	147	124	139	131
	Dry	**26**	**24**	36	36	34	33	22	21	15	14
		457	**315**	517	317	313	252	181	156	175	165
Development	Oil	**590**	**543**	466	433	552	499	520	490	497	453
	Gas	**565**	**490**	610	551	807	740	540	518	485	453
	Dry	**25**	**22**	42	39	57	53	60	57	58	55
		1,180	**1,055**	1,118	1,023	1,416	1,292	1,120	1,065	1,040	961
		1,637	**1,370**	1,635	1,340	1,729	1,544	1,301	1,221	1,215	1,126
Success ratio *(percent)*		**97**	**97**	95	94	95	94	94	94	94	94

(1) Western Canada.
(2) Includes non-operated wells.
(3) Excludes stratigraphic test wells.

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Financial Highlights										
Sales and operating revenues, net of royalties	**$ 12,664**	$ 10,245	$ 8,440	$ 7,658	$ 6,384	$ 6,596	$ 5,066	$ 2,787	$ 2,023	$ 2,282
Net earnings (loss)	**$ 2,726**	$ 2,003	$ 1,006	$ 1,370	$ 796	$ 629	$ 398	$ 91	$ (8)	$ 55
Earnings per share										
Basic	**$ 6.43**	$ 4.72	$ 2.37	$ 3.26	$ 1.91	$ 1.51	$ 1.24	$ 0.34	$ (0.03)	$ 0.20
Diluted	**$ 6.43**	$ 4.72	$ 2.37	$ 3.25	$ 1.90	$ 1.50	$ 1.24	$ 0.34	$ (0.03)	$ 0.20
Capital expenditures (1)	**$ 3,201**	$ 3,099	$ 2,379	$ 1,902	$ 1,707	$ 1,474	$ 803	$ 706	$ 829	$ 601
Total debt	**$ 1,611**	$ 1,886	$ 2,204	$ 2,094	$ 2,740	$ 2,572	$ 2,726	$ 1,725	$ 1,485	$ 1,014
Debt to capital employed *(percent)*	**14**	20	26	27	36	38	43	51	51	43
Reinvestment ratio *(percent)* (2)	**70**	80	110	91	78	79	59	142	204	132
Return on average capital employed *(percent)* (3)	**27.0**	22.8	13.0	18.9	12.3	10.8	11.9	7.3	4.3	7.2
Return on equity *(percent)* (4)	**31.8**	29.2	17.0	26.4	17.9	16.3	20.5	13.7	7.2	12.2
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**111.0**	64.6	66.2	71.6	65.4	46.4	42.8	22.3	23.7	23.6
Medium crude oil *(mbbls/day)*	**28.5**	31.1	35.0	39.2	44.8	47.2	20.8	4.2	3.9	4.0
Heavy crude oil & bitumen *(mbbls/day)*	**108.1**	106.0	108.9	99.9	95.1	83.8	53.5	42.1	42.0	41.9
	247.6	201.7	210.1	210.7	205.3	177.4	117.1	68.6	69.6	69.5
Natural gas *(mmcf/day)*	**672**	680	689	611	569	573	358	251	233	246
Total production *(mboe/day)*	**359.7**	315.0	325.0	312.5	300.2	272.8	176.8	110.4	108.4	110.6
Total proved reserves, before royalties *(mmboe)*	**1,004**	985	791	887	918	927	872	430	431	421
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**62.5**	57.5	53.7	63.6	59.3	59.5	60.6	61.9	54.8	27.5
Upgrading differential *($/bbl)*	**$ 26.16**	$ 30.70	$ 17.79	$ 12.88	$ 10.81	$ 17.91	$ 13.77	$ 6.49	$ 7.85	$ 8.54
Pipeline throughput *(mbbls/day)*	**475**	474	492	484	457	537	528	394	412	417
Refined Products										
Light oil products sales *(million litres/day)*	**8.7**	8.9	8.4	8.2	7.7	7.6	7.4	7.6	6.0	4.5
Asphalt products sales *(mbbls/day)*	**23.4**	22.5	22.8	22.0	20.8	21.4	20.2	17.1	19.5	17.7
Refinery throughput										
Prince George refinery *(mbbls/day)*	**9.0**	9.7	9.8	10.3	10.1	10.2	9.2	10.2	9.9	10.3
Lloydminster refinery *(mbbls/day)*	**27.1**	25.5	25.3	25.7	22.0	23.7	23.4	17.9	21.9	21.5
Refinery utilization *(percent)*	**90**	101	100	103	92	97	93	80	91	91

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(2) Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).

(3) Capital employed for purposes of this calculation has been weighted for 2000.

(4) Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.

Board of Directors

Victor T. K. Li

Canning K. N. Fok

Victor T. K. Li, Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Li is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited. He is Deputy Chairman and Executive Director of Hutchison Whampoa Limited, Executive Director and Chairman of Cheung Kong Infrastructure Holdings Limited, and of CK Life Sciences Int'l., (Holdings) Inc. Mr. Li is an Executive Director of Hongkong Electric Holdings Limited and a Director of The Hongkong and Shanghai Banking Corporation Limited.

Canning K. N. Fok (2), Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. He is Chairman and a Director of Hutchison Harbour Ring Limited, Hutchinson Telecommunications International Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and Hongkong Electric Holdings Limited. Mr. Fok is the Deputy Chairman and a Director of Cheung Kong Infrastructure Holdings Limited and a Director of Cheung Kong (Holdings) Limited.

William Shurniak, Deputy Chairman,
a resident of Limerick, Saskatchewan has been a Director of Husky Energy Inc. since 2000. Mr. Shurniak is a Non-Executive Director of Hutchison Whampoa Limited and a Director and Chairman of Northern Gas Networks Limited.

R. Donald Fullerton (1), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2003. Mr. Fullerton is retired and serves as a corporate director of a number of private companies and is a Director of the Li Ka Shing (Canada) Foundation.

Martin J. G. Glynn (1), Director,
a resident of Scotland, has been a Director of Husky Energy Inc. since 2000. Mr. Glynn recently retired as the President & Chief Executive Officer of HSBC Bank USA N.A.

Brent D. Kinney (4), Director,
a resident of Dubai, United Arab Emirates, has been a Director of Husky Energy Inc. since 2000. Mr. Kinney is Chief Executive Officer and a Director of Sky Petroleum Inc., and a Director of Dragon Oil plc., Western Copper Corporation and Benchmark Energy Ltd.


William Shurniak


R. Donald Fullerton


Martin J. G. Glynn


Brent D. Kinney


Holger Kluge


Poh Chan Koh


Eva L. Kwok


Stanley T. L. Kwok


John C. S. Lau


Wayne E. Shaw


Frank J. Sixt

Holger Kluge [2,3,4], Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2000. Mr. Kluge is a Director of Hutchison Whampoa Limited, Hongkong Electric Holdings Limited and Shoppers Drug Mart Corporation.

Poh Chan Koh, Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Ms. Koh is the Finance Director of Harbour Plaza Hotel Management (International) Ltd.

Eva L. Kwok [2,3], Director,
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mrs. Kwok is a Director, Chairman and Chief Executive Officer of Amara International Investment Corp. She is a Director of the Bank of Montreal Group of Companies, CK Life Sciences Int'l., (Holdings) Inc., Cheung Kong Infrastructure Holdings Limited and the Li Ka Shing (Canada) Foundation.

Stanley T. L. Kwok [4], Director,
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mr. Kwok is a Director and President of Stanley Kwok Consultants. He is a Director and President of Amara International Investment Corp. and a Director of Cheung Kong (Holdings) Limited.

John C. S. Lau, President & CEO, Director,
a resident of Calgary, has been a Director of Husky Energy Inc. since 2000. Prior to joining Husky in 1992, Mr. Lau served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

Wayne E. Shaw [1,3], Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2000. Mr. Shaw is a Senior Partner at Stikeman Elliott LLP, Barristers & Solicitors and a Director of the Li Ka Shing (Canada) Foundation.

Frank J. Sixt [2], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. He is the Chairman and a Director of TOM Online Inc. and TOM Group Limited, and Executive Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited, and a Director of Cheung Kong (Holdings) Limited, Hutchison Telecommunications International Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and the Li Ka Shing (Canada) Foundation.

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

(1) Audit Committee
(2) Compensation Committee
(3) Corporate Governance Committee
(4) Health, Safety & Environment Committee

Officers/Executives

John C. S. Lau

Robert J. Peabody

Donald R. Ingram

James D. Girgulis

HUSKY ENERGY INC.

John C. S. Lau, President & CEO
Mr. Lau was appointed to his position in 1993 and is responsible for Husky's corporate direction, strategic planning and corporate policies, and a member of the Company's Board of Directors. Before joining Husky he served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

Robert J. Peabody, Chief Operating Officer, Operations & Refining
Mr. Peabody is responsible for managing Husky Energy's upstream operations including Western Canada conventional, heavy oil, east coast operations, frontier and international exploration and development, and exploration and production services. He is also responsible for managing refining, upgrading and ethanol production activities. Prior to joining Husky in 2006, he led four major businesses for British Petroleum in Europe and the United States. Mr. Peabody is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Donald R. Ingram, Senior Vice President, Midstream & Refined Products
Mr. Ingram has been an officer of Husky since 1994. He joined the Company in 1982 and has more than 30 years' experience in the midstream and downstream business. Mr. Ingram is a Certified Management Accountant (CMA) and a fellow of the Society of Management Accountants of Canada (FCMA).

James D. Girgulis, Q.C., Vice President, Legal & Corporate Secretary
Mr. Girgulis was appointed Vice President, Legal & Corporate Secretary of Husky Energy in 2000. Previously he was General Counsel & Corporate Secretary of Husky Oil Limited. Prior to joining Husky he held positions with Alberta and Southern Gas Co. and Alberta Natural Gas Company. Mr. Girgulis was called to the Alberta Bar in 1982 and was appointed Queen's Counsel in 2005.

HUSKY OIL OPERATIONS LIMITED

L. Geoffrey Barlow, Vice President & Controller
Mr. Barlow was appointed Controller in 2000 and promoted to Vice President & Controller in 2003. He was previously Controller and a member of the management team at Renaissance Energy. Mr. Barlow is a Chartered Accountant and a member of the Institute of Chartered Accountants of Alberta and the Financial Executive Institute of Canada

Ronald J. Butler, Vice President, Corporate Administration
Mr. Butler is responsible for human resources, health, safety and environment, risk management, office services, real estate, diversity, and materials and service management. He is an experienced human resources practitioner and leader with extensive oil and gas experience. Prior to joining Husky he was Vice President, Human Resources with BP Canada and formerly Manager, Human Resources of Amoco (U.K.) Exploration Company. Mr. Butler is a Past-President and current member of the Human Resources Association of Calgary and a Past Director of the Human Resources Institute of Alberta.

Edward T. Connolly, Vice President, Heavy Oil
Mr. Connolly was appointed Vice President, Heavy Oil in 2006 and has responsibility for increasing both heavy oil reserves and production. Previously he was Manager, Drilling, Well Completions & Facilities Construction with Talisman Energy Canada, and Facilities Construction Project Manager with BP Canada. Mr. Connolly is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Robert S. Coward, Vice President, Western Canadian Conventional Production
Mr. Coward became a corporate officer in 1993 and has served with Husky since 1977. He was appointed Vice President, Western Canada Conventional Production in 2005 and is responsible for optimizing the value of Husky's assets by increasing both reserves and production, and by controlling costs. Mr. Coward is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

L. Geoffrey Barlow

Ronald J. Butler

Edward T. Connolly

Robert S. Coward

J. Michael D'Aguiar

Catherine J. Hughes

Garry P. Mihaichuk

David R. Taylor

Roy C. Warnock

Bill Watson

Ruud B. Zoon

J. Michael D'Aguiar, Treasurer
Mr. D'Aguiar joined Husky as Treasurer in 2002, and is responsible for the treasury department and associated financial functions. He has extensive financial experience in the international upstream oil industry. Prior to joining Husky he was Chief Financial Officer of Ranger Oil.

Catherine J. Hughes, Vice President, Exploration & Production Services
Ms. Hughes was appointed Vice President, Exploration & Production Services in 2005, and is responsible for the strategies and execution plans for surface land, mineral land, drilling and completions, construction operations, reservoir engineering and reserves. Prior to her appointment with Husky, she was President of Schlumberger Canada, and has worked in a variety of operational, technical and management positions in the United States, the United Kingdom, France, Italy and Nigeria.

Garry P. Mihaichuk, Vice President, Oil Sands
Mr. Mihaichuk joined Husky in 2005, as Vice President, Heavy Oil. Appointed to his current position in 2006, he has responsibility for developing Husky's oil sands assets. He brings with him more than 30 years of experience in executive positions in the energy, petrochemical and infrastructure sectors, and has served with Mancal Corporation, TransCanada, TransCanada Transmission, Amoco Corporation, Amoco Orient and Dome Petroleum.

David R. Taylor, Vice President, Exploration
Mr. Taylor has responsibility for for capitalizing on Husky's quality assets in Western Canada and offshore Canada's East Coast, China and Indonesia. Previously he was Vice President of Exploration for Renaissance Energy, and held senior technical and executive positions at Renaissance, Chauvco Resources, Imperial Oil and Exxon. Mr. Taylor is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Roy C. Warnock, Vice President, Upgrading & Refining
Mr. Warnock has more than 25 years of experience in oil refining and upgrading, and joined Husky in 1983. He served as the Manager of Husky's Prince George refinery and the Lloydminster Upgrader, before his appointment as Vice President, Upgrading & Refining. Prior to Husky, he held a number of engineering and operations positions with Imperial Oil. Mr. Warnock is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and Association of Professional Engineers and Geoscientists of Saskatchewan.

Bill Watson, Vice President, Engineering & Project Management
Mr. Watson was appointed Vice President, Engineering & Project Management in 2004, and brings more than 30 years of experience in the energy business to Husky. Previously he was Vice President of Triton Equatorial Guinea Inc., a wholly owned subsidiary of Amerada Hess, and held many management and executive positions with Marathon Oil Company including President of Marathon Canada Ltd.

Ruud B. Zoon, Vice President, East Coast Operations
Mr. Zoon joined Husky Energy in 2004 as General Manager, East Coast Development, and was appointed Vice President, East Coast Operations in 2005. Based in St. John's, Newfoundland and Labrador, he is responsible for all aspects of Husky's East Coast operations including the White Rose development. Prior to joining Husky he worked in leadership roles in the Netherlands, United Kingdom, South Africa, China and United States. He has worked for Sonoil B.V., Bluewater Energy Services B.V. and Mobil Oil Corporation. Mr. Zoon has been a member of the Society of Petroleum Engineers since 1984.

Investor Information

Common Share Information

Year ended December 31		2006	2005	2004
Share price	High	**$ 83.00**	$ 69.95	$ 35.65
	Low	**$ 58.00**	$ 32.30	$ 22.73
	Close at December 31	**$ 78.04**	$ 59.00	$ 34.25
Average daily trading volumes *(thousands)*		**605**	664	482
Number of common shares outstanding, December 31 *(thousands)*		**424,269**	424,125	423,736
Number of weighted average common shares outstanding *(thousands)*				
	Basic	**424,206**	423,964	423,362
	Diluted	**424,206**	423,964	424,303

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.

Toronto Stock Exchange Listing: HSE

Outstanding Shares

The number of common shares outstanding (in thousands) at December 31, 2006 was 424,269.

Transfer Agent and Registrar

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado, in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

Auditors

KPMG LLP
2700, 205 Fifth Avenue S.W.
Calgary, Alberta
T2P 4B9

Annual and Special Meeting

The annual and special meeting of shareholders will be held at 10:30 a.m. on Thursday, April 19, 2007 in the Palomino Ballroom, at the New Round Up Centre, Twelfth Avenue S.E. and Third Street S.E., Calgary, Alberta.

Corporate Office

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Website

Visit Husky Energy's home pages at www.huskyenergy.ca
Wenchang website:
www.huskywenchang.com
White Rose website:
www.huskywhiterose.com

Husky's Dividend History

Declaration Date	Quarter Dividend	Special Dividend
February 2007	$ 0.50	$ 0.50
October 2006	0.50	
July 2006	0.50	
April 2006	0.25	
February 2006	0.25	
October 2005	0.25	1.00
July 2005	0.14	
April 2005	0.14	
February 2005	0.12	
November 2004	0.12	0.54
July 2004	0.12	
April 2004	0.12	
February 2004	0.10	
November 2003	0.10	
July 2003	0.10	1.00
April 2003	0.09	
February 2003	0.09	
November 2002	0.09	
August 2002	0.09	
May 2002	0.09	
February 2002	0.09	
November 2001	0.09	
August 2001	0.09	
May 2001	0.09	
February 2001	0.09	

Additional Publications

The following publications are available on Husky's website or through the Investor Relations department:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

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